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TNO report

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Sector Outlook: Geothermal power increase in the Netherlands by enhancing the capacity

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Summary

A large part of the primary energy consumption in the Netherlands is the demand for heat, which makes investments in sustainable and durable sources of heat worthwhile. But currently the geothermal sector in The Netherlands experiences a decrease in number of newly developed geothermal systems with a slow stagnation of the total produced geothermal power. One of the reasons for the low developed of geothermal systems are flow limiting problems.

To tackle the aforementioned issue, in the Sector Innovation Strategy (Dutch: BIA – branch innovatie agenda) report an inventory will be made of flow enhancing technologies without unintended side effects (so called soft stimulation) that are presently available, and those which will become available in the next few years. In other words, the aim is to find technologies which are primarily focused on creating more flow from the geothermal reservoir, increasing the capacity of geothermal systems for direct use of heat.

In order to do so, the flow increase of the conventional geothermal installations and tapping into higher temperatures from greater depths will be pursued.

<u>Geology of the Netherlands between 2-4 kilometers depth</u>

The main focus is done in the following two formations: the Permian Rotliegend Slochteren Formation and the Triassic Main Buntsanstein. The mineral composition of the Rotliegend reservoir rock is highly variable and is therefore important to have a profound knowledge of the stratigraphy and rock composition of the reservoir. Thus, the potential fit of the reservoir for geothermal operations could be estimated. Generalized facies description of the Rotliegend deposits are described in the table below.

Table 1.1 Generalized facies description of Rotliegend deposits in the Netherlands

Facies	Sediment type	Major mineralogical aspects relevant for the choose of stimulation techniques
Fluvial deposits	Coarse grained sandstones and/or conglomerates; Fine to medium grained sediments; Mudstones	Dominated by detrital grains; Relatively low clay content but cements like carbonates and/or sulphates are common. However, the more fine grained deposits are dominated by higher clay contents.
Aeolian deposits	Well-sorted sandstones; Generally good reservoir quality	Dominated by detrital grains; Relatively low clay content but cements like carbonates and/or sulphates are common
Playa lake deposits	Intercalation of fine to medium grained sandy deposits with clay-rich sediments	Dominated by clay-rich successions, varying authigenic minerals like carbonates, sulphates, quartz, etc. Lower porosity and permeability can be expected compared to fluvial and aeolian deposits

On the other hand, deposition of the Triassic Buntsandstein was governed by the development of a large fluvial system in which clastics were transported. The development of the rocks comprising the Buntsandstein has strongly been governed by the Hardegsen extentional phase.

Similar to the Rotliegend, mainly fluvial and aeolian facies exists in the Triassic Main Buntsandstein, early cementing often including quartz and dolomite. All this influences the choice of the stimulation technique.

Promising Soft Stimulation Technologies

Taking into account that the technology should be available in the next 4-5 years, undefined side-effects should be minimal (or non-existent) and the technology should be suitable for the conditions in the Dutch subsurface, focus on soft stimulation will be made on the following technologies:

- acidization
- hydraulic tensile (Mode-1) stimulation, and
- special drilling techniques (radial jetting and fishbone drilling)

Acidization

Acid treatments are used to react and remove mineral phases that restrict fluid flow and due to its low cost, is becoming more and more common. The goal of this treatment is to improve well productivity or injectivity by enhancing rock permeability without damaging the host rock. Type of rock, number and thickness of the permeable zone, extent of skin damage and level of steam fraction are the design factors when designing the acid treatment (Akin, et al. 2015).

Of the two basic acidizing operations that can be conducted related to injection rates and pressures, only matrix acidizing will be addressed in detail, the one that is widely considered as soft stimulation technique in geothermal well operations.

Matrix acidizing
Performed below fracturing rate and pressure, matrix stimulation is accomplished by injecting a low pH fluid to dissolve and/or disperse materials that impair well production.

Hydrochloric, HCl (typically used in carbonate reservoirs) and hydrofluoric, HF (with HCl typically used in sandstone reservoirs) acids are used in different percentages (15% HCl for carbonate and 12% HCl + 3% HF for sandstones being the most common concentrations) to dissolve blocking minerals. Corrosion inhibitors and intensifiers are also added to the acid mixtures to reduce the corrosion rate of the casing and equipment, using pre-flush and post-flush to reduce the formation of insoluble precipitates.

Several studies have shown the utility of chemical stimulation in geothermal wells (Straw 1980; Epperson 1983; Bareli et al. 1985; Barrios et al. 2002; Serpen and Türeyen 2000; Nitters et al. 2000).

Soft hydraulic stimulation

Injecting fluids at high rate and pressure increases pore pressure of the formation, opening new or pre-existing fractures and hence, increasing permeability. The following lines will be focused on hydraulic fracturing if tensile fractures are generated (and/or opened), the so called Mode-1 fracturing. Using this particular soft-stimulation technique the risk of inducing earthquakes is limited.

In this report, the controlling parameters that trigger hydraulic fracturing or shearing (i.e. stress state and orientation of the fractures) have been studied in order to identify the best way for applying soft hydraulic fracturing and for preventing any shear failure.

Taking into account the previous, could be stated that for small differential stress, hydraulic fracturing and opening of tensile fracture will be favoured and shear failure prevented, while in medium and high differential stress environment, the risk of triggering slip on critically stressed fractures might be high. One way to overcome the latter is to perform multi-stage hydraulic fracturing.

The following table shows that effects vary considerably depending on the treatment and well design, bearing in mind that matrix acidizing job could cost and order of magnitude less than hydraulic fracturing.

Table 1.2 Performance enhancement for simplified skin effect assumptions. Bilateral is a scenario with two vertical wells 100m apart at reservoir level.

	Skin	Improvement	Combining	Slanted	Bilateral	Acid	Frac
Slanted	-1.5	19%	→		60-70%	64%	180%
Bilateral	-3.4	56%	→			90%	300-400%
Acid 1 m	-2.2	30%	→				180%
Frac 100 m	-6.1	180%	→				

Special drilling techniques

Radial jetting
Radial jet stimulation is done (in theory) by creating lateral openings (typically set in groups of four at the same depth) at 90 º angles apart. In 2015 TNO published a report on Radial Drilling for Geothermal applications (Peter eta al; 2015) explaining that this technology is currently becoming commercially available. However, documented cases are rare (only five were found) and has never been tested yet or demonstrated in siliciclastic (sandy) geothermal reservoirs.

Fishbone drilling
A fishbone well is a well in which has a number of parallel multilaterals trunk off a main wellbore, which is often placed horizontally to connect the reservoir vertically throughout a long well in one short pumping operation (carried out in about half a day, not requiring additional fluids or pumps). According to Fishbone AS company, this technique can be applied both in sandstone and carbonates.

Test cases

Two projects with low flow rates were assessed in order to get a better understanding of the previously described technologies:

- Rotliegend test case: increase the flow of conventional geothermal installations
- Triassic test case: increase the power by tapping into higher temperatures form greater depths

Rotliegend

Several studies on cuttings, geology, gamma ray log, mud cake, etc. were carried out in Rotliegend (first test case) leading to the following statement: weighing easiness of application vs skin improvement, the primary technology to consider would be acidization (taking into account that no all soft technologies can be applied because geothermal system is in operation). Before doing so, deep evaluation of the characteristics of the reservoir (composition, structure, permeability, porosity, temperature and pressure and properties of the reservoir fluids) and the assessment of the formation damage should be done. In case this technique fails, hydraulic mode-1 stimulation or radial jetting can be considered. These two techniques can increase considerably the potential of the reservoir for geothermal applications but it's important to highlight that none of them have been neither tested nor demonstrated in geothermal siliciclastic reservoirs.

<u>Triassic</u>

The potential flow rate of a doublet drilled into the Main Buntsandstein has been calculated by T&A Survey (2013) and the information about the susceptibility of the same formation to acid stimulation was derived from NAM report 'Memorandum SPC/3 no. 653/86-KDZ-2 Acid response test (1986), where porosity and permeability of nine core plugs before and after stimulation jobs are presented. T&A 2015 survey has also been consulted.

Considering the latter, the following table can be presented for different scenarios, ex- or including acid stimulation.

Table 1.3 P50 geothermal power as resulting from different choices for (especially) the permeability range. The skin as a result from acidizing taken from T&A (2013, paragraph 2.3.1.1)

Source	Permeability [mD]	Stimulation	P50 power [MWth]
T&A 2013	4-15-150	-	10.2
T&A 2013	4-15-150	Acid	18.1
T&A 2013	1-100-485	-	45.8
T&A 2013	1-100-485	Acid	64.6
TNO (based on T&A 2015)	1-5-3-	-	2.6
TNO (based on T&A 2015)	1-5-30	Acid	4.7

Hydraulic stimulation (mode-1) has also been considered for the second test case, along with the possibility of drilling a horizontal well. In order to assess the potential of both techniques, the permeability and the direction and distribution of the fractures have been analysed.

For hydraulic stimulation, table 4 shows the results for different scenarios.

Table 1.4 Selected DoubletCalc results for different scenarios for (especially) the permeability range. The skin as a result from hydraulic fracturing taken from T&A (2013, appendix 3). Scenarios in grey based on T&A (2015), negative skin added by TNO.

Source	Permeability [mD]	Well diameter in reservoir ["]	Stimulation	P50 power [MWth]	Flow rate [m³/hr]	Pump pressure [bar]
T&A 2013	4-15-150	8.5"	frac (skin -5.5)	28	225	135
T&A 2013	4-15-150	8.5"	frac (skin -7)	49	388	135
T&A 2015	1-100-485	5.5"	frac (skin -5.5)	68	548	130
T&A 2015	1-100-485	5.5"	frac (skin -5.5)	76	618	130

TNO (based on T&A 2015)	1-5-30	5.5"	frac (skin -5.5)	7.7	70	130
TNO (based on T&A 2015)	1-5-30	5.5"	frac (skin -7)	14	121	130

Conclusions

In summary, when relatively limited performance enhancement is necessary (<50%), it can be sufficient to perform matrix acidizing. A bilateral design with acid treatment may result in up to 90% enhancement. Slant or horizontal drilling may, under circumstances, add to the increase of the productivity index (PI).

For higher performance gain, soft hydraulic stimulation can be considered for low differential stress environments. In case of high differential stress environments, soft stimulation can be adapted by using multi-stage.

Complementary to both, possible thermal effects of cold water injection should be taken into account.

Recommendations

Based on the study presented above, the following recommendations are given for the geothermal sector.

For acidization:

- Design the acid treatment based on: the type of formation damage, and knowledge on the local mineralogy, multiple fluids and pumping stages, the drilling mud composition, and reactions between fluids and formation minerals considering the fast reaction kinetics at high temperatures at depth.
- Monitor prior to, during and after the acid treatment operation in order to predict the evolving damage skin factor successfully.

For hydraulic stimulation:

- Although jetting of different lithologies is possible in lab environment, this is not directly true for in-situ conditions. The applicability of radial jet drilling requires more detailed investigation of the site specific conditions and more sophisticated modelling to get a more accurate estimate of the expected revenues.
- Monitoring of the results of jetting directly after operations and on the longer term should provide insight in the effectiveness and can provide a basis for the realization of durable results.

Contents

1 Introduction

A large part of the primary energy consumption in the Netherlands (almost 40% according to RVO) is the demand for heat. This makes investments in a sustainable source of heat worthwhile. Geothermal energy, which provides year-round, sustainable heat, can fulfil an important role in the energy mix of the future.

The geothermal sector in The Netherlands experiences a decrease in number of newly developed geothermal systems. A slow stagnation of the total produced geothermal power was observed for the first time since 2014. In 2014, 2 out of 13[1] geothermal installations were (temporarily) idle due to technical, flow limiting problems. This is a significant bottleneck for the acceleration, or even continuation, of the development of conventional geothermal systems for direct use of heat. The sector organization has the ambition to break through the impasse and give a positive impulse to increase the geothermal power in The Netherlands. To this extend they want to work on solutions for the sector as a whole for conventional geothermal systems and the enhancement of flows from geothermal plays which are currently considered to be unsuitable due to low permeability by burial or cementation. This will not only widen the depth range for direct use of heat, but will also make current unsuitable locations worthwhile to reconsider.

Geothermal energy is a sustainable energy source with the lowest subsidy (SDE+/SEI) per produced unit of energy. The technology was already demonstrated for agricultural applications (greenhouses) where it produces heat from depths between 2 to 3 kilometers, with corresponding temperatures ranging from 70 to almost 100 °C.

Although the applicability of direct use of geothermal heat has been demonstrated, it is not yet considered to be a mature technology. New challenges arise from day-to-day operations and building experience by the sector. The tackling of arising challenges is not a driver for investments to increase the performance by definition, because the subsidy is limited to an upfront estimated production and/or the currently used materials are not (yet) amortized.

In addition, increasing the capacity by tapping into deeper formations (to a depth of 4 kilometers) where flow is limited due to burial driven compaction, has not yet been demonstrated in the Netherlands. This increase could potentially harness great potential for larger groups of agricultural companies, industry/companies with a higher heat demand (> 100 °C) or district heating for offices and households. For these types of projects, the subsidy will be advantageous, because higher capacities can still be opted upfront, although results of soft stimulation (for both conventional and deeper geothermal targets) in order to enhance the flow and long(er) term side effects are still unclear.

[1] Delfstoffen en Aardwarmte in Nederland: jaarverslag 2014 (statistics include ‘Mijnwater E-centrale Heerlen)

This Sector Innovation Strategy report presents an inventory of capacity enhancing technologies without unintended side effects (so called *soft stimulation* techniques) that are presently available, or will become available in the next few years. These technologies will be placed in an outlook (purely technical, although there are also non-technical aspects) for application in geothermal wells within the depth interval of 2 – 4 kilometers, to increase the capacity of geothermal systems for direct use of heat. By use of this technology outlook, the geothermal sector gains insight in promising technologies, and receives directions for further research and development in order to make those technologies available for geothermal operators within the next 4 to 5 years.

Note that the aim is to find technologies which are *primarily* focused on enhancing the flow capacity of the geothermal reservoir (technically speaking, to create 'negative skin'). This means that in all cases it is implicitly assumed that the well itself operates as expected (skin = 0, so the well has been properly cleaned after drilling, possibly underreamed), but the reservoir from which the hot water is produced is deteriorated or deteriorating, or when a higher flow is required/desired than the natural reservoir conditions support. Operations and strategies for damaged wells were subject of previous projects[2] or solutions are commercially available in the market.

1.1 Challenge

Previous studies show that the total amount of recoverable heat is in principle sufficient to cover the present-day energy consumption of the whole agricultural sector (Van Wees et al., 2012). The Dutch Central Bureau of Statistics (CBS, 2009) indicates that there are about 5500 greenhouse companies in the Netherlands, of which half of them are active in fruits and vegetables. Geothermal energy is not an option for all greenhouse companies, for either technical or economic reasons. Even if only a small portion is considered to qualify, the total installed capacity would not exceed 15-20% - typically the ‘tipping point’ for innovations[3] - marking the current geothermal operators as the innovators and early adopters.

[2] Relevant TNO reports:
Degens et al., 2012: BIA Geothermal – TNO Umbrella Report into the Causes and Solutions to Poor Well Performance in Dutch Geothermal Projects - TNO rapport: TNO 2012 R10719
Wasch et al., 2013: Geothermal Energy – Scaling potential with cooling and CO2 degassing – TNO 2013 R11661
Bressers et al., 2014: Lead depositions in geothermal installations – TNO 2014 R11416

[3] ‘Law of Diffusion of Innovation’: Theory that describes the spreading/ adaptation of innovations within a group (e.g. a sector). The theory is based on the work by Gabriel Tarde, and made popular by the innovation theory from Everett Rogers (1962).

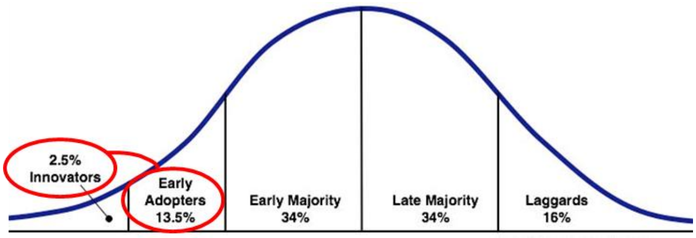

Figure 1.1 Direct use of geothermal heat in The Netherlands is still very innovative and immature. Current developments are by the innovators and early-adopters following the Law of Diffusion of Innovation

In order to support the growth of the efficiency (high heat production) or direct use of geothermal heat for both existing and new geothermal installations and on a national scale towards the tipping point it is possible to:

- Increase the flow (and thereby power) of conventional geothermal installations (to a depth of 3 kilometers)
- Increase the power by tapping into higher temperatures from greater depths (to a depth of 4 kilometers)

The depth of 3 kilometers is somewhat arbitrary. It is considered to be an approximate maximum depth at which an unstimulated doublet may work. At larger depth, stimulation is considered to be a requirement. For geothermal operators with one or more geothermal system(s) experience the setbacks by disappointing reservoir porosity / permeability and thereby the negative depreciation of their business case due to low flow from their well, high costs (OPEX) for repair and stimulation, aggravated by the societal component and decreasing results from their well by quality degradation of their geothermal reservoir nearby the well.

This project investigated the options for both existing and planned installations and provides an outlook for the next 4 to 5 years ahead by including promising techniques that have not been applied in the Netherlands.

1.2 Structure of the report

The report provides an overview of the technologies which are presently available, under development or reported in peer-reviewed literature. As the interest is limited to application of the technologies in the Dutch subsurface, an outline of the geology within the predefined depth interval of 2 – 4 kilometers depth is presented, including the Rotliegend and Triassic formations. Combining the knowledge from the subsurface and the technologies, result in a shortlist of promising technologies for the Dutch geothermal sector. These technologies will be described in more detail, which is the basis of a test case. The test case not only validates the tailored inventory, but provides insight in knowledge gaps and development requirements also.

To conclude, the findings will be translated to a technical outlook for application of soft stimulation technologies for the next 4 to 5 years. This outlook gives a first indication of opportunities that may support the maturation of the technologies.

2 Overview table of stimulation techniques in geothermal wells

The table below shows an overview of well stimulation techniques based on an extended literature review. All the techniques for geothermal wells are similar to those employed in the oil industry to drill and complete wells in productive reservoirs. The description of the geological context in which the techniques are proven is reported based on quick-scan for geothermal wells. The mentioned costs are the direct costs of the technique and are estimated and ranked from: very low, low, moderate, high and very high. Very low is about 60 k€, very high is 250-300 k€. Note that for a full enhancement project, more costs will account for the total required investment.

Table 2.1: Longlist of (soft) stimulation technologies for geothermal systems

Type of treatment	Well Stimulation Technique	Description	Drawbacks	Tested in GT	Geological context	Case study	Potential Service Company	Indicative Costs*
Chemical	Matrix Acidizing (HCl or HCl+HF)	Always performed below fracturing rate and pressure. Acid flows through the matrix with reactions taking place in existing pores and natural fractures. Matrix stimulation is accomplished by injecting a fluid with low pH to dissolve and/or disperse materials that impair well production and is mainly used to treat the near-wellbore region.	Scaling minerals (and clogging). Limited active acid penetration. Casing corrosion Flowbacks (HSE concerns).	Yes and well documented in hydrocarbon industry.	Sandstones Carbonates Granites	Soultz-sous-Forets, France Los Azufres field, Mexico	Halliburton (USA) Schlumberger Fangmann GPC Instrumentation Process (France)	Low-Moderate
Chemical and mechanical	Fracture Acidizing	Performed above fracturing rates and pressures. Acid is injected into the geothermal reservoir to create fractures, as acid is transported, dissolution etching occurs and conductivity is increased (Kalfayan, 2008)	Induced seismicity (inherent to fracture). Fracture overlapping.	Yes	Carbonates Sandstones		Halliburton Schlumberger Fangmann	Moderate
	Coiled Tubing Acid Stimulation	Conventional acid treatment using continuous length of small-diameter steel pipe and related surface equipment (Akin, et al., 2015) Chemical and mechanical removal.	The same than in conventional matrix acidizing	Yes	Carbonates	Alaşehir Geothermal Field, Turkey	GPC Instrumentation Process (France) Trican (USA) Schlumberger	Moderate
Hydraulic	Hydraulic Fracking (Tensile mode)	High rate injections pressurizes the reservoir, leading to the creation of new fractures or to the enhancement of the permeability of pre-existing ones.	Induced seismicity (social concern in the NL). Less risk than in hydro shearing.	Yes	Sandstones Carbonates Granites Volcanics	Soultz-sous-Forets, France	Baker Hughes Citadel Energy Schlumberger	Very High
	Hydro shearing (Shear mode)	Use of moderate pressures to open very small cracks (1-2 mm) with the goal of creating a network of thousands of permeable cracks within a reservoir. Different from hydraulic fracturing (HF) used in the oil and gas industry, which uses much higher pressures to initiate new tensile fractures.	Induced seismicity (social concern in the NL).	Yes	?		AltaRock Energy	High
Thermal	Thermal Fracturing	A phenomenon that occurs when a fluid (e.g. produced water, seawater, aquifer water or surface water), considerably colder than the receiving hot formation is injected (Flores, Davies, Couples, & Palsson, 2005). It can be combined with other stimulation techniques such as matrix acidizing and fracture acidizing.	Induced micro seismicity	Yes	Volcanic	Rotokawa field, New Zealand		Very low
Thermal and Hydraulic	Thermal (cryogenic) Fracking**	Fracture technique which combine hydraulic fracking and fractures caused by thermal stress due to the injection of cold liquid CO_2 (Mueller et al., 2012).				None yet		
Special drilling techniques	Radial Jetting	Hydraulic jetting is used to create small-diameter laterals up to 100 m long from a main backbone (TNO report, 2015). It is also referred to as radial jet drilling or radial drilling.	No major risks to the well or environment have been identified. (limited experiences)	No		None yet	Radial Drilling PetroJet Coiled Services USR Drilling Services (USA)	High
	Fishbone	Stimulation technique invented by *Fishbone AS* in which a (horizontal) backbone is completed with many small and short laterals (up to 100 laterals of 12-24m long). Fishbone stimulation creates more uniform drainage pattern in the reservoir because of the lateral placement of the jets (Freyer, Kristiansen, Vadla madland, Omdal, & Omdal, 2009). Only applicable in new wells.	No major risks to the well or environment have been identified. (limited experiences)	No, successful pilots in ECBM and carbonates	Carbonates (using hydraulic jetting) Sandstone ('Dreamliner' technique which uses drilling)	None yet	Fishbones AS (Norway)	High
Mechanical	Casing Perforation	Stimulation technique designed to access cased-off permeable horizons by perforating the well casing. Designed to provide effective flow communication between a cased wellbore and a	Casing-strength reduction (casing failure) Widely apply in oil & gas industry.	Yes (with acidizing)	Any		Halliburton Schlumberger TCO, Norway Expro	Moderate

Type of treatment	Well Stimulation Technique	Description	Drawbacks	Tested in GT	Geological context	Case study	Potential Service Company	Indicative Costs*
		productive reservoir (Aqui & Zarrouk, 2011)						
	High Energy Gas Fracturing (HEGF) or Explosive Stimulation	Tailored pulse fracturing technique which uses propellants to obtain controlled fracture initiation and extension. This stimulation treatment is restricted to the open hole, because the shock wave could damage well casing and production hardware. Quite common technique of the petroleum industry.	Instability of explosives at high temperatures Micro seismicity (?)	Yes	Sandstones Carbonates Granites Volcanics	Geyser's Field, Northern California	Servo-Dynamics, Inc.- STRESSFRAC® (USA)	Low
Acoustic	Acoustic Well Stimulation (AWS)**	Use of simple ultrasonic wave source, the interaction between the acoustic field and the saturated porous rock can cause changes in the permeability or removal of plugging (Aqui & Zarrouk, 2011)	Not invasive.	Not to our knowledge			Siberian-Urals Geological oil servicing Company Ltd Applied Seismic Research (ASR)	Difficult to evaluate with the current status of knowledge
Electric	Electric Stimulation**	Use of electric current to stimulate the well. The effect could either be electrothermal or electrodynamic type. The electrothermal effect is evident in the near wellbore zone during heating with infrared or high frequency or microwaves. The electrodynamic effects create a cleaning of the bottom hole formation zone from clay particles restoring or improving the well productivity (Aqui & Zarrouk, 2011)	Process is not well understood yet. Penetration in the formation is small.	Not to our knowledge				Difficult to evaluate with the current status of knowledge

* Further investigation needs to be done (difficult to assess due to differences at every well job).

** Infancy stage of development.

3 Promising enhancement technologies

In this chapter a shortlist is extracted from the broad inventory of Chapter 2. The criteria are:

1. the technology should be available in the next 4-5 years;
2. side-effects are or should be minimal or non-existent;
3. the technology should be applicable to prevailing conditions in the Dutch subsurface.

The longlist shows two technologies which are currently too immature to be considered promising for the next 4 to 5 years; acoustic and electric stimulation. Mechanical Stimulation (both casing perforation and High Energy Gas Fracturing (HEGF) or Explosive Stimulation) and shear fracturing are not considered to qualify as ‘soft stimulation’, as they may embody unintended side-effects like environmental hazards and/or induced seismicity. Focus will therefore be on soft stimulation on the basis of:

- acidization (paragraph 3.1)
- hydraulic tensile (or Mode-1) stimulation (paragraph 3.2)
- special drilling techniques (paragraph 3.3).

These three techniques will be described in more detail below.

Thermal or cold fracturing is rather an *effect* than a *technology.* Therefore it is not discussed in detail in this document. Thermal fracturing is a process well known from water injection wells in the oil and gas industry. Thermal fractures known from literature are always a side effect of current operations. It is not inconceivable that thermal fracks may evolve from side effect to technology in the near future. A study currently carried out by TNO focuses on the development of thermal fractures in geothermal doublets, as a result of enhanced cooling. The report will be out early 2016.

3.1 Acid stimulation

Acid treatments utilize acids that react and remove mineral phases that restrict fluid flow. The acidization of geothermal wells is becoming more common. The techniques have been adapted from the oil and gas industry (Entingh, 1999). Acid stimulation is a most popular technique in the oil and gas industry because of low cost. Nitters et al. remark that in the Groningen gas field 16 jobs were carried out for just 600,000 US$ or 37,500 US$ per job[4]. Crowe et al. (1992) even report 5,000 US$ per treatment. The target of this treatment is to improve or to keep up well productivity or injectivity without damaging the host rock by enhancing rock permeability. Among the physico-chemical processes that commonly occur in the subsurface when acidifying are:

[4] Note: this only concerns 'out-of-pocket' money for operations to third parties. Total project costs will exceed the aforementioned costs.

- dissolution of minerals (pore- or pore-throat-blocking minerals, or formation cement)
- etching of mineral surfaces
- mobilization of particles by decomposition of the rock structure
- inhibition of secondary or tertiary reaction products
- control of reactivity of mineral surfaces (clay swelling)

The criteria for the design of the acid treatment are type of rock formation, number and thickness of the permeable zones, extent of skin damage, and level of steam fraction (Akin, et al., 2015).

Two basic types of stimulation or acidizing operations can be conducted related to injection rates and pressures. Injection rates resulting in pressures below fracture pressure are termed 'matrix acidizing', while those above fracture pressure are termed 'fracture acidizing (Figure 3.1).

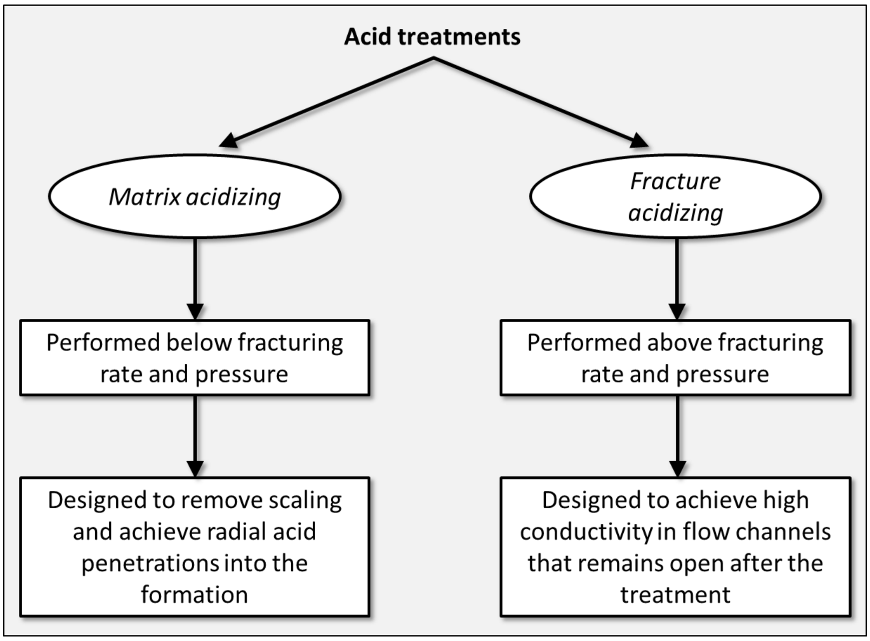

Figure 3.1 Acid treatment techniques: matrix acidizing and fracture acidizing. After (Morales Alcala, 2012).

In this report, only matrix acidizing is addressed in detail, which is widely considered as a soft stimulation technique in geothermal well operations.'

In contrast to the term 'soft stimulation', the designation 'soft acidizing' (Ventre and Ungemach, 1998) indicates that highly diluted acid is injected from the surface for a prolonged period of time (eg., 60 hours instead of approximately a single hour for a conventional acid job). The volume of injected acid is approximately the same as during a normal acid job, but, instead of addressing only formation damage, also casing damage can be treated. Soft acidizing is applied in the Netherlands by NAM and Vermilion (Erik Ham pers. comm.). As the steel casing will be afacted by soft acidizing, an inhibitor should be applied. Continuous pH control of the injected fluid, for instance for correcting the pH after degassing, is sometimes referred to as 'super soft acidizing' (Noga et al., 2013).

3.1.1 *Matrix acidizing*

Acid is forced through the matrix[5]. Chemical reactions take place in existing pores and natural fractures (Figure 3.2). Matrix stimulation is accomplished by injecting a fluid with low pH to dissolve and/or disperse materials that impair well production. It is mainly used to treat the near-wellbore region. The process is executed below fracturing pressure to avoid the initiation of hydraulic fractures. If the latter occurs, the acid will not dissolve the matrix but remain in the newly formed fracture instead.

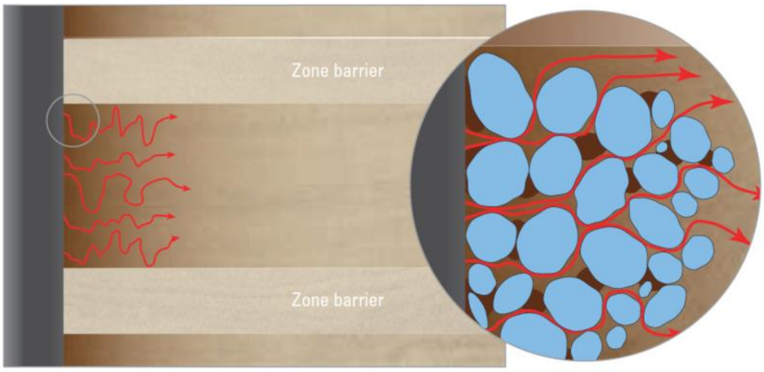

Figure 3.2 Matrix stimulation removes or bypasses damage in the pore spaces between grains and leaves the zone barriers within the reservoir intact (Davies & Kelkar, 2007).

Matrix acidizing is probably the most widely used technique because of its relative low cost compared to other techniques, and because it is a relatively simple stimulation technique to improve the well productivity significantly (Nevito Gomez, 2006). It can be applied in clastic or carbonate rocks. Various acids are used in conventional acidizing treatments. The most common and effective are:

- <u>Hydrochloric, HCl (typically used in carbonate reservoirs).</u> This is the most widely used acid in treatments, with concentrations ranging between 7.5% and 28%, the most common being 15%. It will dissolve calcium carbonate ($CaCO_3$), dolomite ($CaMg(CO_3)_2$), siderite ($FeCO_3$), and iron oxide (Fe_2O_3).
- <u>Hydrofluoric, HF (with HCl typically used in sandstones reservoirs)</u>. Usually a mixture of HCl and HF (hydrofluoric acid) and generally 12% HCl and 3% HF. It will dissolve clay materials in the formation, along with feldspars and quartz. The HF will react with Na, K, Ca and Si in the clays to form insoluble precipitates, so it might be advisable to pre-flush with HCl, but do make a careful case-specific consideration.
- <u>Organic acids and breakers such as enzymes</u> are often used for well cleaning operations, but especially 'slow acting' organic acids[6] can also be used for improving the productivity / injectivity (possibly in combination with 'quick acting' HCl.

The concentration of each acid depends on the reservoir characteristics and the specific purpose for the treatment. Corrosion inhibitors and intensifiers are also

[5] Matrix: finer grained material lying in between the larger grains or particles in sedimentary rocks

[6] E.g. acetic and formic acids

added to the acid mixtures (pre-flush, main-flush and post-flush, see in section 3.1.2) to reduce the corrosion rate of the casing and equipment by the acid.

For the chemical reactions associated with acidization, please see appendix B.

3.1.2 *Effective operations*

The parameters taken to design an acid treatment are (Barrios, Guerra, Jacobo, & Mayorga, 2012):

- Type of acid for the main treatment
- Strength of such acid for the main treatment
- Volume of the main treatment
- Pre-flush and Main-flush and Post-flush composition and volume
- Additive selection: corrosion inhibitors, corrosion inhibitor intensifiers, clay controllers, fine and iron controllers
- Operational parameters: injection rate, injection pressure, etc
- Results of acid dissolution tests.

Matrix acidizing in geothermal wells is usually conducted in three main steps: pre-flush, main flush and over-flush (Malate, 2003; Portier, André, & Vuataz, 2007).

- The **pre-flush** is a fluid pumped ahead of the main treating flush to displace the formation brine. Multiple pre-flush stages are sometimes used to address multiple damage mechanisms and prepare the surface for the main treatment fluids.
- The **main flush** is the fluid used to remove the potentially existing damage (residual mud or other precipitates). In a carbonate acid treatment is typically HCl while in a sandstone acid treatment is typically a mixture of HF and HCl, known as “mud acid”.

    - If any carbonates are present in a sandstone, these should be removed with a pre-flush of HCl.
    - If a sandstone formation contains more than 15% carbonate, it is recommended to consider the formation as carbonate formation (the well should be acidized with HCl only).
    - If the cementing material is carbonate, it is not recommended to use HCl greater than 10%.
    - If (pore-filling) kaolinite is present in the clay fraction, fresh water should be avoided and NH_4Cl should be added to avoid a swelling problem.
    - If chlorite is present in the clay fraction, iron control should be added.

- The **over-flush (post-flush)** in a sandstone acid treatment is the fluid after the main flush completion usually brine or fresh water. It serves to push the main fluid containing the dissolved damage material further away into the formation and minimize inevitable precipitation reactions from taking place near wellbore.

An example of a general treatment procedure for a geothermal well (completed open-hole or with a liner) is given in Table 3.1. Data collected from the NLOG.nl website show volumes range from about 14 m³ (Triassic GAG-2 and GAG-3 wells) to 40 m³ (Rotliegend L10-3) for the pre-flush phase, and up to 80 m³ for the main flush in L10-3.

Step	Treatment
Pre-flush and cooling	Fresh water: 1.6·m³/min (trough tubing and annulus, to cool wellbore temperature to below 93°C)
Acid pre-flush	38 – 190 m³; 0.3 – 1.6 m³/min
Main acid (main flush)	38 – 190 m³; 0.3 – 1.6 m³/min
Over-flush	Diluted acid or brine, several hours at maximum rate. Fresh water poses risk.

Table 3.1 Generalized acid treatment procedure for a geothermal well (Modified after Kalfayan, 2008)

1990				
Mineralogy		Permeability		
		> 100 md	20 to 100 md	< 20 md
High quartz (> 80%), low clay (< 10%) High clay (> 10%), low silt (< 10%) High clay (> 10%), high silt (> 10%) Low clay (< 10%), high silt (> 10%)	< 200°F	12% HCl, 3% HF	10% HCl, 2% HF	6% HCl, 1.5% HF
		7.5% HCl, 3% HF	6% HCl,1% HF	4% HCl, 0.5% HF
		10% HCl, 1.5% HF	8% HCl,1% HF	6% HCl, 0.5% HF
		12% HCl, 1.5% HF	10% HCl,1% HF	8% HCl, 0.5% HF
	> 200°F	10% HCl, 2% HF	6% HCl, 1.5% HF	6% HCl, 1% HF
		6% HCl, 1% HF	4% HCl, 0.5% HF	4% HCl, 0.5% HF
		8% HCl, 1% HF	6% HCl, 0.5% HF	6% HCl, 0.5% HF
		10% HCl, 1% HF	8% HCl, 0.5% HF	8% HCl, 0.5% HF

Figure 3.3 Acid system guidelines for sandstones (Crowe et al. 1992). 200 °F = 93 °C.

3.1.3 *Study cases*

Use of chemical stimulation in geothermal wells is well known and it has been applied performed in geothermal wells over the last 30 years (Strawn 1980; Epperson 1983; Barelli et al. 1985; Barrios et al. 2002; Crowe et al. 1992, Serpen and Türeyen 2000, Nitters et al. 2000). A summary of the main chemical stimulation experiments carried out in geothermal fields is given in Table 3.2, showing variable results (based on Portier et al. 2009).

Results of chemical treatments in selected geothermal fields.

Geothermal field	Chemical agents used	Number of treated wells	Variation of the injectivity index before and after chemical treatment ($kg\ s^{-1}\ bar^{-1}$)	Ref.
Bacman (Philippines)	HCl–HF	2	0.68–3.01 0.99–1.40	Buning et al. (1995)
Leyte (Philippines)	HCl–HF	3	3.01–5.84 0.68–1.77 1.52–10.80	Malate et al. (1997); Yglopaz et al. (1998)
Tiwi (Philippines)	HCl–HF	1	2.52–11.34	Buning et al. (1995)
Mindanao (Philippines)	HCl–HF	1	Successful	Buning et al. (1997)
Salak (Indonesia)	HCl–HF	1	4.70–12.10	Pasikki and Gilmore (2006)
Berlín (El Salvador)	HCl–HF	5	1.60–7.60 1.40–8.60 0.20–1.98 0.90–3.40 1.65–4.67	Barrios et al. (2002)
Las Tres Vírgenes (Mexico)	HCl–HF	2	0.8–2.0 1.2–3.7	Jaimes-Maldonado and Sànchez-Velasco (2003)
Los Azufres (Mexico)	HCl–HF	1	3.3–9.1	Flores et al. (2006)
Beowawe (USA)	HCl–HF	1	Successful	Epperson (1983)
The Geysers (USA)	HCl–HF	1	No effect	Entingh (1999)
Coso (USA)	HCl and NTA[a]	30	24 wells successful	Evanoff et al. (1995); Rose et al. (2007)
Larderello (Italy)	HCl–HF	5	11–54 4–25 1.5–18 Successful 11–54	Cappetti (2006)
Fenton Hill (USA)	Na_2CO_3	1	About 1000 kg of quartz were dissolved and removed from the reservoir but no impedance reduction resulted.	LANL (1977)
Fjällbacka (Sweden)	HCl–HF	1	Efficiency of acid injection in returning rock particles.	Sundquist et al. (1988); Wallroth et al. (1999)

[a] NTA: nitrilotriacetic acid ($C_6H_9NO_6$).

Table 3.2 Results of chemical treatments in selected geothermal fields (after Portier et al.,2009).

3.1.4 Risks and consequences of matrix acidization

Various authors commented on the success rate of acid stimulation like Gidley (1985, Paccaioni and Tambini (1993) and Nitters et al. (2000). A stimulation is considered successful if either the inflow performance is significantly improved, or the skin factor significantly lowered. The success rate they report varies. Paccaioni and Tambini (1993) report 78-91% (the highest success rates pertain to dolomite and limestone, the lowest to poorly consolidated sandstone), while Nitters et al. (2000) state that the worldwide failure rate is 60-70%. Failure is attributed to incorrect field procedures, the use of an incorrect stimulation fluid (or treatment design), or selecting the wrong candidate well (Paccaioni and Tambini 1993).

The use of acids in well stimulated can create various problems some of which include (Portier, André, & Vuataz, 2007):

- Inadvertent injection of solids or release of fines that could plug the formation
- Use of incompatible additives or improper mixing procedures
- Re-precipitation of acid reaction products (scale deposition which commonly in the wellbore or in liner slots/perforations). See Table 3.3.
- Mobilisation and/or precipitation of NORM[7] and other elements which become out of balance in the brine solution
- Loss of near-wellbore formation compressive strength
- Formation of emulsions
- Formation of sludge
- Water blocking
- Wettability alteration
- Corrosion of steel, etc.

It should be noted that for the last mentioned complication (corrosion) in geothermal projects in the Netherlands flow back is not required as the reactors will be used completely and thereby disappear and that the standard procedure of acidizing is in line with the Dutch legislation.

Precipitate	Origin
Calcium Fluoride (CaF_2)	Carbonate-HF reaction CaF_2 can be caused by an inadequate HCl preflush to remove calcium ions from calcite cementing materials or to flush calcium chloride completion fluids away from the near wellbore.
Amorphous silica	Clay and silicate dissolution in HF. Amorphous silica results from both secondary and tertiary HF acidizing reactions.
Sodium and potassium fluosilicates	Feldspar and illite clay dissolution in HF produce these primary reaction products. They can also form if seawater or sodium or potassium brines are mixed with spent HF.
Sodium and potassium fluoaluminates	Silico-aluminate dissolution in HF. Fluoaluminates, like fluosilicates, occur when spent mud acid (H_2SiF_6) reacts with the formation. They can also form if seawater or sodium or potassium brines are mixed with spent HF.
Aluminium hydroxides and fluorides	Clay and feldspar dissolution in HF can cause these precipitates.

[7] Naturally Occurring Radioactive Material

Iron compounds	Iron minerals or iron oxides (rust) can react with HCl-HF to produce these compounds.

Table 3.3 Possible precipitates in sandstones acidizing based on Schlumberger report (Portier, André, & Vuataz, 2007).

Acid additives could be used as a precautionary or corrective measure to the well problems outlined above. Acid additives normally used in practice include (Kalfayan 2008):

- Corrosion inhibitors
- Inhibitor intensifier (often required)
- High-temperature iron control (iron reducing) agent (reacts with dissolved iron and prevents solid precipitation)

Corrosion inhibitors are generally mixed with the treatment fluid at all acid stages. They are formulated to be effective in protecting the metal components the fluid is likely to contact. Iron control is always required in acidizing treatments as the tubing usually contains iron oxide which is easily dissolved by the acid. The control agent prevents redeposition of the iron near the wellbore in the formation.

Other concerns that operators must address when applying matrix acidizing treatments are the following issues (Aboud et al. 2007):

- ***'Flow back of acidizing fluids** — As acidized production wells are returned to production, there are naturally environmental concerns. Geothermal fields are often near populated areas, and wells are tested and flowed to the atmosphere. Noise and odours affecting the local population are of concern for the geothermal operators when flowing back wells after stimulation.*
- ***Limited Information** — Geothermal operation practices differ from oilfield operations in that most geothermal operators do not take steps to obtain, store, analyse and track individual well information and performance trends. Coring, production tests, injection tests, build-up and drawdown tests, and other information that could be important and useful is usually partially or totally missing. A change in mind set of the geothermal industry is necessary in this regard. The benefit of acid stimulation of geothermal wells is apparent even with the minimal information available. Imagine the potential if the gathering of such information were standard practice.'*

3.2 Soft hydraulic stimulation

Hydraulic stimulation by injecting downhole high-pressure fluids[8] is now a standard technique for permeability enhancement of geothermal systems (Petty, Nordin, Glassley, Cladouhos, & Swyer, 2013). The increase of pore pressure in response to fluid injection intends opening new or pre-existing fractures and in consequence an increase of permeability. The technique has been adapted from oil and gas

[8] In a way, a Leak-off Test or Formation Integrity Test (FIT), which are routinely carried out during drilling for testing the formation strength is not very different from hydraulic fracturing. During a FIT, however, the intention is not the destroy the formation integrity. During a (complete) Leak-off Test, the strength of the rock is tested by increasing the pressure until failure. Of course, in a FIT or Leak-off Test, no proppants are used.

reservoir stimulation and two distinct hydraulic stimulation mechanisms can be targeted (Gischig & Preisig, 2015), either

- hydraulic fracturing if tensile fractures are generated (and/or opened) by the local injection of high-pressure fluids, or
- hydraulic shearing if shear failure along pre-existing fractures/faults is triggered by the local injection of high-pressure fluids.

Activating hydraulic fracturing is considered to be a soft-stimulation technique in the sense that the risk of inducing earthquakes is limited (Eaton et al. 2014). In contrast, hydraulic shearing is more risky, and might have been at the origin of the triggering of relatively large seismic events in shale gas stimulations (Wolhart et al. 2006).

This report aims to present the controlling parameters which determine whether the high-pressure fluid injection will activate hydraulic fracturing or hydraulic shearing. Ultimately the goal is to identify the best way for applying soft hydraulic fracturing and for preventing any shear failure.

3.2.1 Principle of hydraulic stimulation

The pore pressure of the porous rock around the borehole is increased by injecting high-pressure fluids downhole.

In the scenario of hydraulic fracturing, when the pore pressure P_f is sufficient to overcome the minimum principal stress σ_3 plus the tensile strength T_0 of the intact rock, a new **tensile fracture** (Figure 3.4 Mode-1) is generated. Following the Griffith criterion, the condition for hydraulic fracturing can be written as:

$$P_f = \sigma_3 + T_0.$$

In the case of pre-existing open fractures close to the borehole and oriented normal to σ_3, the fracture can be opened by only exceeding σ_3, that is:

$$P_f = \sigma_3$$

In the scenario of hydraulic shearing, the rise of pore pressure will decrease the effective normal stress (σ_n - P_f) acting on pre-existing fractures. Once the effective normal stress clamping the two facing planes of the fractures will be low enough, the shear stress (τ) will be sufficient to drive slip; **shear fracturing** (Figure 3.4 Mode-2). According to Mohr-Coulomb's law, the condition for shear failure can be written as

$$\tau = c + \mu (\sigma_n - P_f)$$

with µ the friction coefficient (generally between 0.6 and 1.0) and c the cohesion. The magnitude of σ_n and τ acting on a pre-existing fracture depends on its orientation relatively to the principal stresses σ_1, σ_2, and σ_3. The pre-existing fractures already critically stressed will fail first because of their optimum orientation regarding the orientation of the principal stresses.

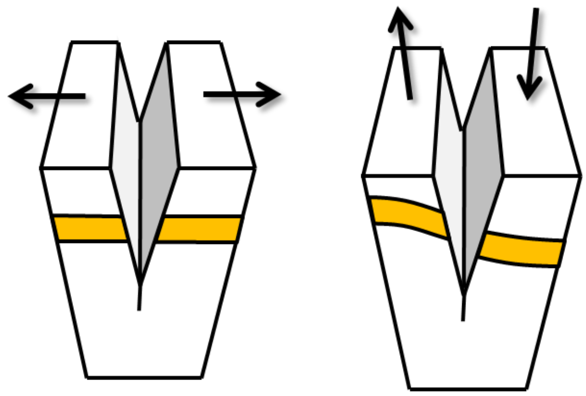

Figure 3.4 Types of fracturing: Mode-1 (Tensile) fracturing opens the rock and Mode-2 (shearing) is fracturing driven by slip

3.2.2 Hydraulic fracturing promoted in low differential stress environment

The two scenarios (either hydraulic fracturing or hydraulic shearing) can be synthetized by Mohr circle representation (see Figure 1 for the 2D representation). The Mohr circle representation is a useful way to visualize the failure conditions relatively to the in-situ stress conditions. Increasing the pore pressure, the effective stresses are reduced and the Mohr circles are shifted to the left up to the critical point where they hit the failure envelope. Depending on the differential stress (σ_1 - σ_3) at depth, the rise of pore pressure will either open a tensile fracture or trigger shear along a pre-existing fracture. For small differential stress, hydraulic fracturing and opening of tensile fracture will be favoured and shear failure prevented.

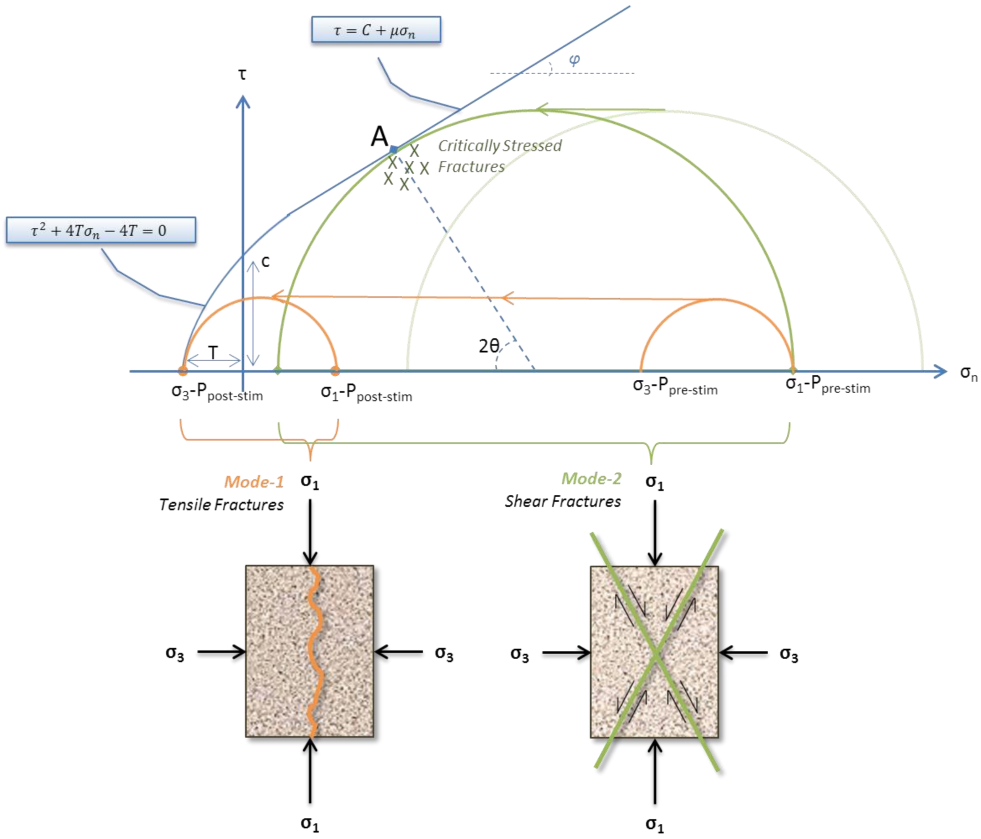

Figure 3.5 Mohr-Coulomb Circle representation of the effect of increasing pore pressure for two differential stress environments (green for shear and orange for tensile). For low differential stress (orange), new tensile fractures will be generated; that is the basis for hydraulic fracturing. For high differential stress (green), shear failure might be triggered on a set of critically stressed fractures, that is the basis for hydraulic shearing. More specifically, in order for tensile failure to occur the differential stress needs to be lower than $4T_0$.

3.2.3 Hydraulic fracturing strategy adapted to high differential stress conditions

Figure 3.5 shows that re-activing slip in any pre-existing critically stressed fractures can be avoided in a low differential stress environment by increasing the pore pressure. Only tensile fractures are generated in this way.

However in a medium to high differential stress environment, Figure 3.5 shows that rising the pore pressure the risk of triggering slip on a pre-existing critically stressed fracture might be high. Determining the direction and magnitude of the principal stresses jointly with the orientation of pre-existing fractures is therefore an important element of hydraulic fracturing strategy.

In the scenario of a high differential stress environment it is therefore crucial to select short packed intervals which avoid intersecting pre-existing fractures critically stressed. One way to overcome the risk of re-activating slip on critically stressed fractures is to perform multi-stage hydraulic fracturing, i.e. to create a stack of tensile fractures as it is performed for recent shale gas operations.

3.2.4 *Low risk of induced seismicity associated with hydraulic fracturing*

The occurrence of relatively large seismic events (magnitude of ~3) recently observed in EGS (Enhanced Geothermal System) (Majer et al. 2007) have been attributed to hydraulic shearing, i.e. slip along large pre-existing fractures.

The explanation for the lower risk of induced seismicity in hydraulic fracturing setting may come from recent dynamic rupture modelling (Garagash & Germanovich, 2012). These models identify the fundamental conditions under which the reactivation of fault slip by elevated pore pressure leads to the nucleation of dynamic (earthquake) rupture.

The modelling work of Garagash and Germanovich (2012) reveals that quasi-static stable sliding is promoted along fractures with low shear stress and on which slip is induced by high overpressure (pore pressure close to normal stress). These environmental conditions correspond to hydraulic fracturing, that is fractures with orientations close to normal to σ_3 and for which the re-activation requires a large increase of pore pressure. In contrast, when the fracture is critically stressed (i.e. optimally oriented fracture with high shear stress) with only a low overpressure required to reactivate it, unstable (i.e. seismic) slip will be triggered. This is the scenario for hydraulic shearing.

The results of the modelling work of Garagash and Germanovich (2011) are in agreement with recent observations from the induced seismicity sequence at Basel EGS in 2006 (Terakawa, Miller, & Deichmann, 2012). Non-optimally oriented fractures hosted the smallest seismic events and only the largest seismic events have been hosted by critically stressed fractures.

3.2.5 *Thermal effects*

Experience from existing doublets possibly indicates that the well injectivity is sometimes better than anticipated from reservoir simulation studies. In principal, these simulators do not take the thermal effects of cooling the reservoir rock into account. This can act as a natural stimulation mechanism and enhance the injectivity. During injection of colder fluids, thermal stresses and the associated rock contraction can lead to the formation of tensile fractures. This effect, which is well known from cold water injection wells in the oil and gas industry, can be significant during long-term injection of cold fluids.

Numerical models developed by TNO show that the thermal effect can in principle be substantial, and in comparison as effective as hydraulic fracturing. This effect can be predicted and in the future maybe be achieved at operation times, or at the appraisal stage in a single well by prolonged water circulation, in conjunction with the stimulation treatments already discussed.

A tensile thermal fracture, when formed, will remain open as long as the injection pressure is maintained. However, when the injection pressure is lowered (below $\sigma_{h,min}$), the fracture closes again as long as proppants are not used. (note that shear fractures may remain open after the fracturing is performed).

3.2.6 *The use of proppants to keep the tensile fractures open*

During hydraulic fracturing, once tensile fractures have been generated, proppants will need to be used in order to maintain the permeability enhancement after treatment.. This is particularly important in the context of long term permeability enhancement, long-term fluid circulation and optimal heat exchange.

3.2.7 *Estimates of performance enhancement via hydraulic fracturing*

When performing hydraulic fracturing, the productivity Index (PI) and Injectivity Index (II) can be enhanced up to 100% and 180% (Pluymaekers et al., 2015)[9], with fracture lengths of 25m and 100m respectively (Table 3.4).

	Skin	Improvement	Combining	Slanted	Bilateral	Acid	Frac
Slanted	-1.5	19%	→		60-70%	64%	180%
Bilateral	-3.4	56%	→			90%	300-400%
Acid 1 m	-2.2	30%	→				180%
Frac 100m	-6.1	180%	→				

Table 3.4 Performance enhancement for simplified skin effect assumptions. Bilateral is a scenario with two vertical wells 100m apart at reservoir level.

Cost – benefit considerations

Matrix acidizing costs an order of magnitude less than hydraulic fracturing (appr. 500 k€). Additional costs for slanted wells and multilateral wells may well be higher.

For hydraulic fracturing, the total well performance would not differ significantly for a vertical well compared to a slanted well, unless multiple fracs would be generated from a single slanted well.

Table 3.4 illustrates that effects vary considerably depending on treatment and well design. Given the license area there may only be limited scope for developing multilateral wells, but a bilateral well with 100-200m well distance should generally be possible.

Well design: slanted wells, multilateral wells

The PI and II of the wells can be enhanced if the wells are slanted, yielding a performance enhancement of about 20%, which corresponds to a skin of -1.5. Considering multilateral wells, a doubling of the performance can be achieved[10]. Following the analysis, this is valid for a bilateral well consisting of vertical laterals 100 meters apart that act as single well with a skin of -3.5). The skin of slanted wells and acidization can be added. This allows to reach 90% enhancement. However, enhancement (skin) effects of fractures in combination with a slanted well, or multilateral wells combined with slanted wells cannot simply be added.

[9] Hydraulic fracturing stimulation results are less prone to uncertainty, prior to assessment of core data, compared to acid treatment. In the calculation an infinite fracture transmissivity has been assumed, as pressures losses are most likely limited

[10] The skin of two vertical wells at a distance d, is equal to one single well adopting a skin of $-0.5 \times \ln(d/r_w)$, where r_w is well radius and d the distance between the wells.

3.3 Special drilling techniques

3.3.1 Radial jetting

Stimulating a geothermal reservoir by use of radial jetting, is (in theory[11]) done by creating lateral openings (more or less) perpendicular to the well. This is done by bringing down a tube and nozzle, to jet – using water – a radial in the formation. Figure 6 shows the typical setup of laterals (or radials) resulting from radial jetting in a vertical well. They are typically set in groups of four at the same depth at 90° angles apart.

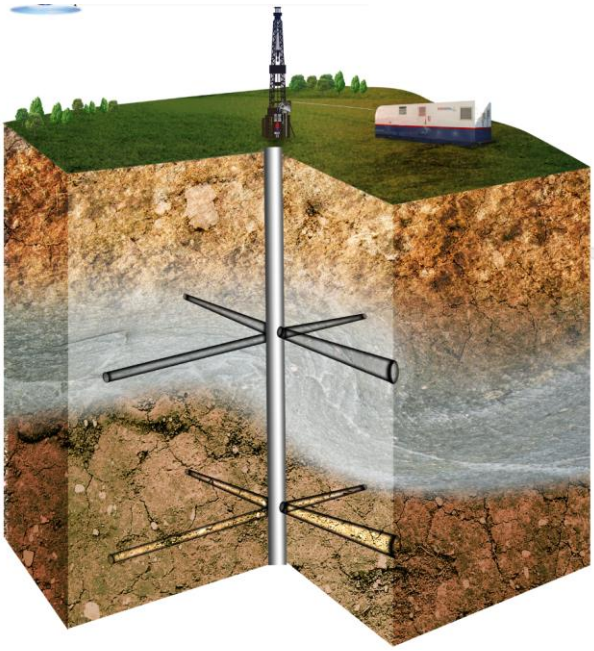

Figure 3.6 Overview of laterals as created by radial jet drilling (http://www.radialdrilling.com/)

In contradiction to conventional drilling with a bit, radials are created by jetting.

The setup of the nozzle head used for jetting is shown in Figure 3.7. There are multiple openings in the nozzle (from end, like the mouth of a garden hoze), one face forward and three or more backwards. The forward nozzle erodes the rock of the formation and by the force creates tensile failure (opening of the rock, see the previous chapter) and cavitation. The backward nozzles jet water backward which creates the forward thrust needed to move the nozzle head forward.

[11] In theory, because the technique is currently not yet applied in geothermal systems. The demonstration of the technique for geothermal purposes is subject of the European project (Horizon 2020) SURE which will start in March 2016.

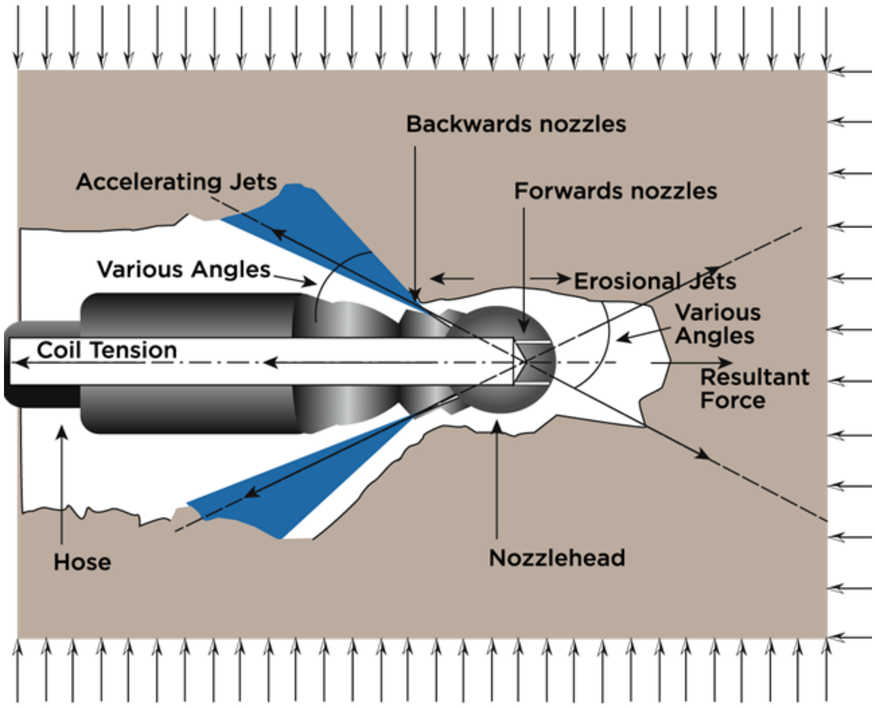

Figure 3.7 Setup of the nozzle head used in radial jetting.

In 2015 TNO published a report on Radial Drilling for Geothermal applications (Peters et al.; 2015). In this report they state that Radial jetting is currently becoming commercially available. The technique has the potential to be competitive with for example hydraulic fracturing in terms of costs, expected (well) performance improvement and public acceptance.

For calculations and examples of the flow enhancement potential, please see chapter 5.1.5.

Using the technique of radial jetting has been reported for a large number of wells, although according to Peters et al. (2015), documented cases are rare and only 5 were found. For the majority of these wells a good initial increase in production is reported, but in some of these cases the initial increase in production declined rapidly and disappeared within a year. Others showed no or hardly any response to the radial stimulation without any given explanation.

A decrease of the initially good production after stimulation by use of radials might be caused by pressure decline in the reservoir due to production and/or because the radials may not be stable. In the few well tests that were done before and after radial stimulation, no increase in productivity could be detected.

Peters et al. (2015) report that the overall, realised performance seems to fall short of theoretical performance and that the reasons for this are not clear at that time. However, it should be realised that the same is true for other well stimulation techniques such as hydraulic fracturing or acid stimulation.

In general, best performance of the radial stimulation was observed for cases with near-well damage.

3.3.2 *Fishbone drilling*

Often the techniques of radial jetting and fishbone drilling are mixed up. A fishbone well is a well in which has a number of parallel multilaterals trunk off a main wellbore, which is (often) placed horizontally to connect the reservoir vertically throughout a long well in one short pumping operations (source: Fishbone AS company website)

According to Fishbone AS, Fishbones operations are simple. To a large extend it doesn't require different operations than regularly are run when drilling a horizontal well. The reservoir liner string are run, after which the liner hanger slips are set. When circulating fluids with the rig pumps, a large number of small diameter laterals jet out from the wellbore to penetrate the reservoir. By means of this technique an operation is carried out in about half a day and it doesn't require additional fluids or pumps.

According to the Fishbone AS company website, fishbones can be applied both in sandstones (and other hard, non-reactive formations) and carbonates. In the sandstones, laterals are drilled, whereas in carbonates numerous laterals are created with acids in a short pumping operation (bullheading[12]) to create the interconnectors within the reservoir.

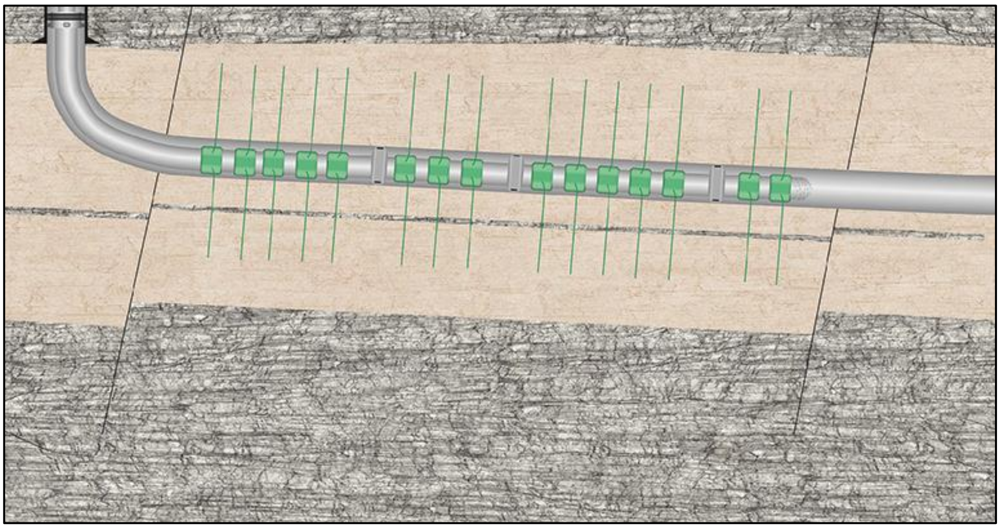

Figure 3.8 Fishbone well. Multiple laterals (in green) extend from the main borehole. From Jorgensen (2015).

3.3.3 *Underreaming*

Underreaming is a technique whereby a relatively slim borehole is widened below the casing by use of a special drill bit that can be lowered through the small diameter casing, and then opened by hydraulic or mechanical means. Underreaming can be applied in open hole gravel-pack completions.

[12] Bullheading refers to the forcing fluids into the reservoir at high pressure, possibly exceeding the pore pressure or even the fracturing pressure. The risk of bullheading is that the fluid enters the weakest formation, and that the direction of the fluid cannot be controlled.

Underreaming is a technique that is sometimes used for safety reasons, e.g. when drilling unknown formations or when gas is possibly expected. The small pilot hole is then widened afterwards. A second reason for underreaming is when extra annular space is required for running a casing.

Alternatively, it could be beneficial to widen the reservoir section in order to facilitate the inflow (in the producer) or outflow (in the injector). As the well face is enlarged, the same volume flow is possible at lower fluid velocity (thereby decreasing the risk of fines mobilisation), or, alternatively, a higher flow rate at similar fluid velocity. This potential improvement is only relevant if the in- or outflow is the limiting factor in a doublet, for instance when formation damage exists in the near wellbore area (skin removal). DoubletCalc can be used to calculate the effect of enlarging the wellbore diameter by changing the 'outer diameter producer / injector' in the input screen. Additionally, apart from possibly removing well damage, a wider borehole facilitates the installation of the completion.

Figure 3.9 Schlumberger 4500 series 6.5" underreaming tool. It can open up to nearly twice its original diameter.

Apparently, this technique cannot be applied anymore after the borehole has been completed using a perforated casing, wire-wrapped screen, slotted liner and / or gravel pack, unless this is removed again.

Figure 3.10 and Table 3.5 present an example of the way DoubletCalc could be employed for evaluating the possible benefits of underreaming. The resulting volume flow and, logically, the geothermal power, is of course depending on the exact doublet configuration and reservoir parameters (see DoubletCalc manual equation 7, Mijnlieff et al. 2014).

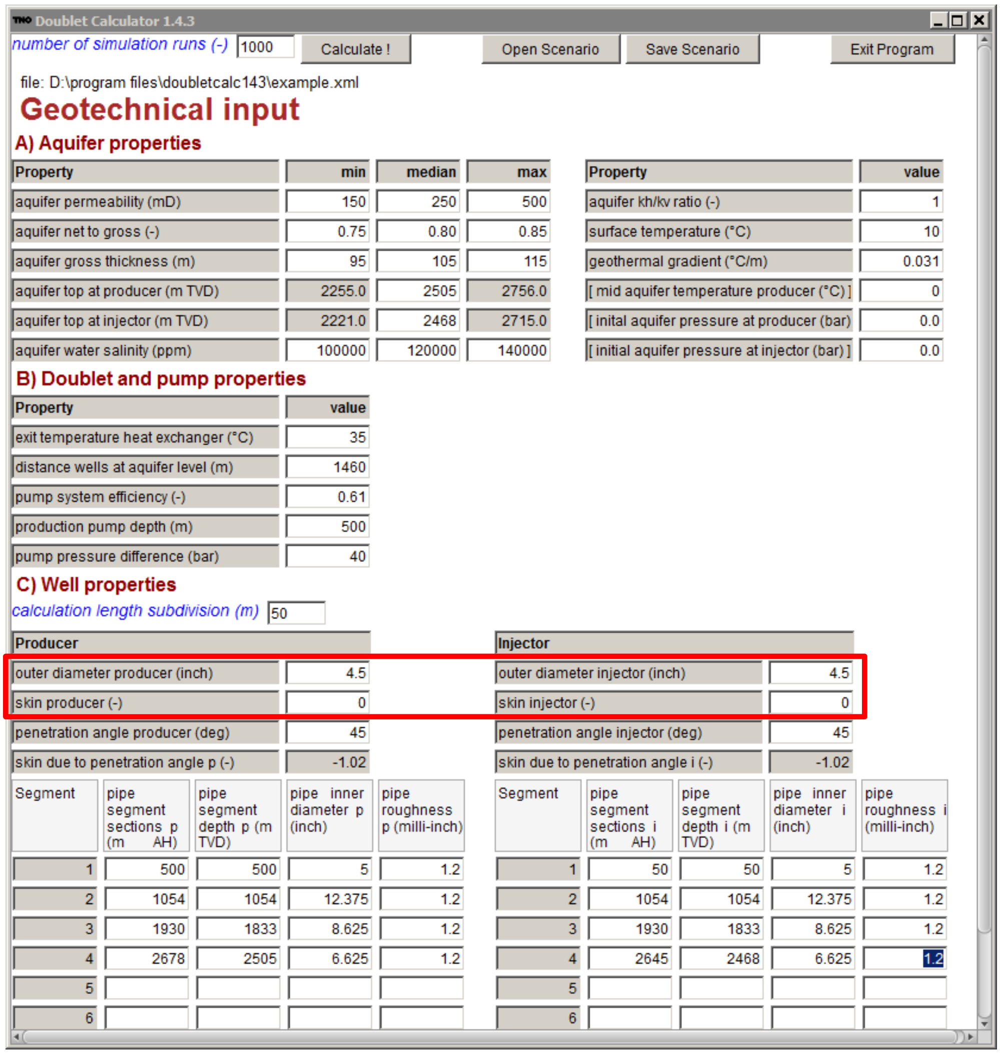

Figure 3.10 DoubletCalc scenario for a hypothetical doublet configuration. In red the parameters that are (possibly) influenced by underreaming.

diameter [inch]	skin [-]	geothermal power [MW]	COP [-]	pump power [kW]	volume flow [m³/h]
4.5	2	6.9	30.2	227	125
4.5	0	8.1	30.4	265	146
7.0	0	8.4	30.5	274	150

Table 3.5 DoubletCalc output for hypothetical situation with small diameter (wellbore damage; skin = 2), and results after damage removal (e.g., by acid flush), and underreaming. At unchanged pump pressure difference, the required pump power increases, but so do the geothermal power, the COP and the volume flow.

3.4 Drawbacks

In general, an increased flow rate can lead to fines migration (which may lead to clogging further in the installation) and may endanger the integrity of the reservoir rock (possibly leading to damage further in the installation). The latter is especially if the reservoir rock is less consolidated like for instance the rocks of Jurassic and Cretaceous age in the Westland area. 'Particles contained in the porous matrix can be released under hydrodynamic forces induced by the fluid mechanics' (Egberts et al. 1995). Egberts et al. (1995) describe a study in this area, in which precipitation of dissolved solids, clay swelling, plugging of pore throuats by fines and blocking of pore throats by gas bubbles are identified as possible sources of formation damage during injection. They carried out coreplug flowtests using solid-free brines. For flow rates between 1 and 7 cm^3/sec they discovered an initially quick decrease in permeability when a critical flow rate (between 1 and 6 cm^3/s) was exceeded, followed by a gradual decrease[13]. For France, fines migration is prevented by keeping flow velocities below to 0.1 or 0.2 m/s.

[13] Note that a flow rate of 1 cm^3/s or 0.0036 m^3/hr through a 1 inch diameter pore plug (0.000161 m^2) equals 890 m^3/hr through a 5" outer diameter borehole in a 100 meter high reservoir (40 m^2).

4 Geology of the Netherlands between 2-4 kilometers depth

This chapter describes the reservoir rocks at moderate depth (2-4 kilometers), that are both relevant to geothermal exploration and candidate for stimulation. This is especially the Permian Rotliegend Slochteren Formation, and the Triassic Main Buntsandstein. The Jurassic and Cretaceous formations from which most of the production of the doublets in the southwestern part of the Netherlands comes are excluded. This choice was made because current flow rates do not hamper the performance of existing geothermal systems, And for future developments the provided knowledge base can be applied and for the same formations and for the deeper lying Jurassic and Cretaceous geothermal targets.

4.1 **Rotliegend**

The depositional system of the Rotliegend Basin was influenced by several variables, e.g. the availability of sediments, climate, the connection to the ocean and tectonic subsidence. The sediments of the Rotliegend Basin were deposited under arid to semi-arid climate conditions in intracontinental basins. The depositional thickness increases from less than 50 m in the South of the Netherlands to not more than 600 m (ref. Southern Permian Basin Atlas)).

The mineralogical composition of Rotliegend reservoir rocks in the Netherlands potentially fit for geothermal operations is highly variable in terms of detrital grains, but especially for the occurrence of cements. However, the choice of a stimulation technique has to be made, amongst other things, based on this mineralogical inventory. It is therefore important to have a profound knowledge of the stratigraphy and rock composition of the reservoir. Table 4.1 summarizes some generalities on the mineralogical inventory. Note that a general statement for the distribution of cements like carbonates and sulphates cannot be given. A more detailed description is provided in Appendix A.

Table 4.1: Generalized facies description of Rotliegend deposits in the Netherlands

Facies	**Sediment type**	**Major mineralogical aspects relevant for the choose of stimulation techniques**
Fluvial deposits	Coarse grained sand-stones and/or conglom-erates; Fine to medium grained sediments; Mudstones	Dominated by detrital grains (e.g. Qz, Fsp, and rock frag-ments); Relatively low clay content but cements like car-bonates and/or sulphates are common. However, the more fine grained deposits (e.g. flooding surfaces) are dominated by higher clay contents. In general, detailed knowledge about the fluvial environment is helpful to predict potential mineralogical inventories.
Aeolian depos-its	Well-sorted sandstones; Generally good reservoir quality	Dominated by detrital grains (e.g. Qz, Fsp, and rock frag-ments); Relatively low clay content but cements like car-bonates and/or sulphates are common
Playa lake deposits	Intercalation of fine to medium grained sandy deposits with clay-rich sediments	Dominated by clay-rich successions, varying authigenic minerals like carbonates, sulphates, quartz, etc. Compared to fluvial and aeolian deposits a lower porosity and perme-ability can be expected

4.2 Triassic

After the Permian Zechstein (which overly the Rotliegend sediments), during which evaporites (salt) were formed, sedimentation continued in the Southern Permian Basin Area. The facies, however, became mainly continental (aeolian, fluvial, lacustrine, paralic, but also some shallow marine). Deposition of the Triassic Buntsandstein was governed by the development of a large fluvial system which transported clastics from the Massif Central and Vosges areas in France northward through the Ruhr Valley Graben, into the West Netherlands Basin and the Off Holland Low. Additionally, the London Brabant Massif served as local source of clastic input. During the earliest Triassic (Induan), the coarse clastics were still trapped in the Ruhr Valley Graben. Later uplift of the hinterland transported the clastic deposits further north into the basin. Influx of course clastics (Lower Germanic Trias) ceased during the Middle Triassic (Upper Germanic Trias). The development (thickness and facies) of the rocks comprising the Buntsandstein has strongly been governed by the Hardegsen extensional phase.

4.2.1 Mineralogical composition relevant for choice of stimulation techniques

Similarly to the Rotliegend, different facies exist in the Volpriehausen, Detfurth, Hardegsen en Solling Formations (see Appendix A), mainly fluvial and aeolian. This influences the choice of stimulation technique. Early cement often includes calcite and dolomite. During burial, others cements may have formed, including quartz. The same statements as made for the Rotliegend in Table 0.1 are generally valid. Because of the complex burial and uplift history, it is extremely important to assess the rock chemistry and diagenetic history of the reservoir before deciding on a stimulation technique.

A more detailed description of the relevant geology can be found in appendix A.

5 Test cases

Two actual projects with (anticipated) low flow rates were assessed in order to obtain better understanding of the applicability of the described technologies:

- **Rotliegend test case:** increase the flow (and thereby power) of conventional geothermal installations (to a depth of 3 kilometers)
- **Triassic test case:** increase the power by tapping into higher temperatures from greater depths (to a depth of 4 kilometers)

The test cases will give insight in the drawbacks, shortcomings and knowledge gaps for applying the soft stimulation technologies in The Netherlands.

5.1 Case Rotliegend

The Middenmeer concession is selected as test case for the Rotliegend. The site consists of two doublets, providing heat for the greenhouses of Agriport A7.

The Middenmeer doublets were drilled in the Slochteren Formation of the Upper Rotliegend Group to a depth of about 2.5 kilometers TVD.

Based on an interference test between the wells MDM-GT-03 and MDM-GT-04, Panterra (2014) the permeability of the GT-03 well is about half of the average permeability which is observed in the GT-04 well; the GT-04 well shows a permeability of 95-115 mD, and from the well test an average permeability is derived of 100 mD between the two wells. MDM-GT-04 was properly reamed and is assumed to have a very low skin. A reasonable fit for the well test could be obtained when assuming:

- partial completion for MDM-GT-03. This would mean that part of the reservoir is not contributing to the flow. The net-to-gross of the reservoir is however very high.
- a large positive skin, possibly caused by insufficient cleaning after drilling.

The latter option would mean that material used or produced during drilling of the well is blocking the near wellbore pores. The applied mud contained CMC polymers which are known to disintegrate quickly after use. Therefore, it is considered unlikely that mud remains are the cause of the low permeability. During drilling Mikhart pills were used to mitigate mud losses. Mikhart is calcium carbonate ($CaCO_3$), used as an (acid soluble) weighting agent to increase the mud weight and circulation material lost in drilling fluids. Those viscous pills could in principle also cause wellbore damage, but breakers (added to the pills) were used to remove the viscous polymers in the pills, thereby . Therefore it is assumed that it is unlikely that remains of the viscous pills are blocking the well.

5.1.1 Problem statement

Three possible scenarios are considered, which were identified to cause clogging issues nearby or within the well:

- The formation of a mud cake;
- Precipitation of minerals, i.e. carbonates or sulphates, originated from the reservoir fluids; Fluid-rock interactions between the formation water and the reservoir rock can lead to the dissolution of minerals and the supply of elements into the water phase. Due to changing physio-chemical conditions near the wellbore mineral precipitation may occur, leading to blocked pore space and decreasing porosity and permeability values.
- Corrosion of the wellbore material and the formation of a scale; The corrosion of the steel (L80 and K55) in a high pressure and temperature environment in combination with saline formation waters could lead to the formation of a scale due to electrochemical reactions and the precipitation of solid mineral. Additional elements for these reactions could also have been supplied from the saline Rotliegend formation water.

5.1.2 Reservoir

As the Middenmeer geothermal system targets the Rotliegend, please see chapter 4.1 and Appendix A for a description of the Rotliegend.

Location specific depositional environment and facies of Rotliegend sediments
The Middenmeer area lies on the southern flank of the east-west striking Southern Permian Basin, formed in the foreland along the northern flank of the Variscan High (Figure 5.1). The Variscan high (of which the Pyrenees are still a product) acted as source areas for Permian sediments (Glennie, 1972; Ziegler, 1990).

In the basin centre a very salty playa lake was developed where evaporates and muds were deposited under influence of an arid climate during Permian age (Glennie, 1972). Fluvial (deposited by rivers) sediments and Aeolian (deposited by wind) sands were deposited near the southern basin margin (Gast et al., 2010; Glennie et al., 1978; Ziegler, 1990).

At the end of the Early Permian a gradual change towards a wetter climate resulted in lake expansion and in the deposition of fine-grained sands in the more marginal areas of the basin (Amthor and Okkerman, 1998).

In the Triassic to Middle Jurassic a regional thermal subsidence initiated crustal extension and rifting (spreading of the crust). This extension phase resulted in the reactivation of existing fracture systems and therewith in block faulting and fracturing of Rotliegend deposits.

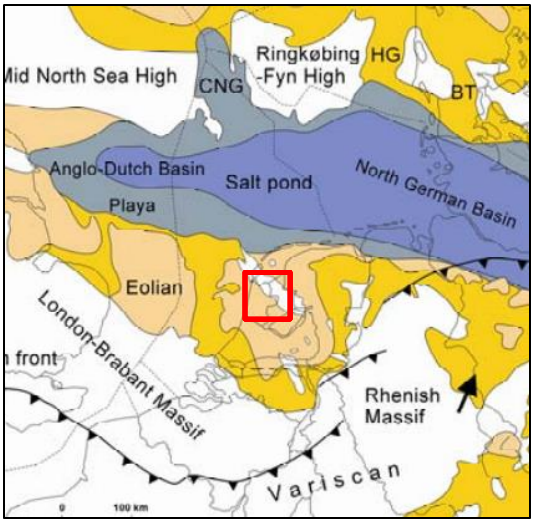

Figure 5.1 Facies and present-day distribution of Rotliegend sediments in the Permian Basin system. The study area (red box), located in a eolian dominated part of the area, lies at the southern flank of the Texel IJsselmeer High. Sketch (clipped to the Netherlands) from Geluk (2005).

Relevance of the Depositional Environment

High permeability and porosity values can be expected in sediments deposited as aeolian sediments or dry sandflat deposits. With increasing clay content, as it occurs typically in damp and wet sandflat deposits, permeability decreases (Figure 5.2).

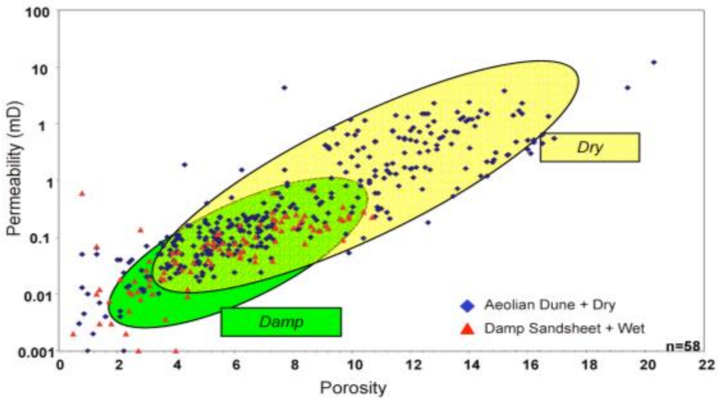

Figure 5.2 Porosity-permeability plot of Upper Rotliegend (Slochteren Formation) sediments from the North German Basin (Gaupp, 2009).

The Middenmeer reservoir dominantly comprises aeolian sediments (ECW 2014, Figure 5.1). However, fluvial sediments show, as for aeolian sandstones, a wider range in porosity and permeability values but are in general less well sorted (Figure 5.3).

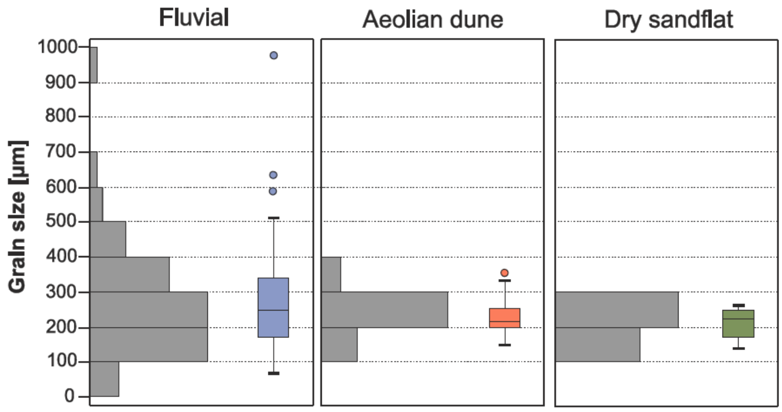

Figure 5.3 Exemplary grain size distribution of sediments attribute to fluvial (n = 56), aeolian dune (n = 20), and dry sandflat (n = 10) deposits from Upper Slochteren sandstones, NE Netherlands (Waldmann, 2011).

Identifying general trends for the composition of sediments from different environments is more complicated. Generally, aeolian sandstones show lower total amounts of clay than damp or wet sandflat deposits. This is in particular important for this study as high clay contents in the reservoir sandstones are not expected. However, detailed analyses from the target horizon are lacking.

Middenmeer reservoir
The injection well MDM-GT-01 has been drilled to the Slochteren Formation of the Upper Rotliegend Group reaching a final depth of 2466 m TVD. The sediments are characterized by aeolian deposits with a good reservoir quality. The local permeability ranges between 53 and 115 mD (based on the various MDM well tests referred in the Panterra reports) and porosity yields 14-18 %. The sandstones are light-red coloured, fine to medium grained at the top, medium grained in the middle and medium/coarse grained at the bottom. Some claystone, dolomite and anhydrite layers are intercalated (ECW 2014).

The most abundant detrital minerals are quartz, K-feldspar and various rock fragments. Authigenic minerals are comprised by quartz, carbonates, sulphates, clay minerals (illite, chlorite, and kaolinite) and ferric oxides. The grains show coatings on the surfaces, which could act as nucleation sites for mineral precipitation during operation.

Cuttings
The lithologs from the MDM-GT-03 and MDM-GT-04 wells are distinctly different (Figure 5.4). In the cuttings of MDM-GT-03 abundant limestone (blue), claystone (green) and anhydrite (pink) is found, whereas MDM-GT-04 contains clean sand. This does not *necessarily* imply that the reservoir is different between the two wells. The difference could also be due to the drilling process. In the cuttings description[14]

[14] A cuttings description (per 5 m-scale) is very different from a core description (mm-scale). For MDM-GT, a certain volume of cuttings from the mud near the shale shakers was taken. From this volume 100 ml of material was sampled, washed and dried. The remaining unwashed part was stored in plastic bags. For washing 2 sieves were used, the bigger one for grains larger than 1,0 mm (=coarse fraction), the smaller one for grains between 0.1 and 1.0 mm (= fine fraction). Clay particles (and other small mud materials) are smaller than 0.1 mm and will be washed through the small sieve. The dried cuttings were described, using a binocular. The column “Lithological

of MDM-GT-03 the anhydrite is marked as 'probably cavings or insufficient hole cleaning', which means that it was interpreted as throughfall from the Zechstein, which was not cased when the Rotliegend was drilled. For the claystone, no specific explanation is given in the cutting descriptions but it may be similar throughfall from the Zechstein.

Alternatively, Henares et al. (2014) described abundant *in situ* anhydrite in Rotliegend rocks in the vintage Kampen exploration well, and the two Koekoekspolder geothermal wells. Here, the anhydrite occurs in layers with thicknesses up to several tens of meters, and of unknown lateral extent. It is interpreted as the cause of the low permeability found in those wells. The (paleo-)locations of the Koekoekspolder and Middenmeer geothermal concessions are comparable in terms of the setting at the border of the Texel-IJsselmeer High, with elevated ground water levels and associated evaporation and salt precipitation during deposition. Therefore It is not impossible that the anhydrite in the MDM-GT-03 well is in situ. Similarly, the clay that was interpreted as throughfall from the Zechstein may have been in situ.

Logs
A well section (Figure 5.7) shows that the quality of the Rotliegend, as derived from the gamma log of the MDM-03 and MDM-GT-01 wells is comparable, most likely meaning that the clay content is comparable. The gamma ray of the other two geothermal wells is higher. This may be caused by:

- increased clay content of the MDM-GT-03 and MDM-GT-04 wells (implying lower reservoir quality and hence permeability) or
- poor calibration of the gamma-tool before the run.

All gamma rays are rather flat. This does not necessarily mean that the sediment compositions remain unchanged. Anhydrite and quartz have a similar gamma ray expression. It is still possible to differentiate between the two, given sufficient data. The anhydrite in Kampen and Koekoekspolder is present as sedimentary grains, sometimes showing desert rose structures. A detailed study of the cuttings may shed more light on the exact cause of the differences. Running a density log would have been useful for determining whether the rocks at MDM-GT-03 contain anhydrite, as anhydrite has a higher density than quartz (Figure 6.3). In situ anhydrite would have implications for a possible acidizing scenario as a rock consisting of pure sand should be treated differently than one containing (abundant) anhydrite. Wellbore damage, by definition occurring in the direct vicinity of the well, can well be removed by acidizing, whereas poor reservoir quality all throughout the reservoir cannot be remediated. Local removal of clay, even if present in the entire reservoir, will still enhance the near wellbore area and inflow. Based on paleo-geographic reconstructions, the depositional environment is dominantly eolian. However, the log patterns observed in some of the Middenmeer wells bears resemblance to Bergermeer (Figure 5.5). The latter was interpreted as fluvial. The interpretation of the depositional environment, therefore, is imporant for predicting

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composition" on the litholog shows the percentages of kinds of the rocks (sand, gravel, flint, clay, etc.) observed with the binocular. White space in the lithological composition column means there has been clay or other very small mud material which has been washed through the small sieve.

the presence of clay, and also the type of clay minerals in the formation. Rossel (1982) reports that Rotliegend sandstones of the southern North Sea that have been buried deeply (>3000m) contain illite (known to be susceptible to swelling, together with smectite).

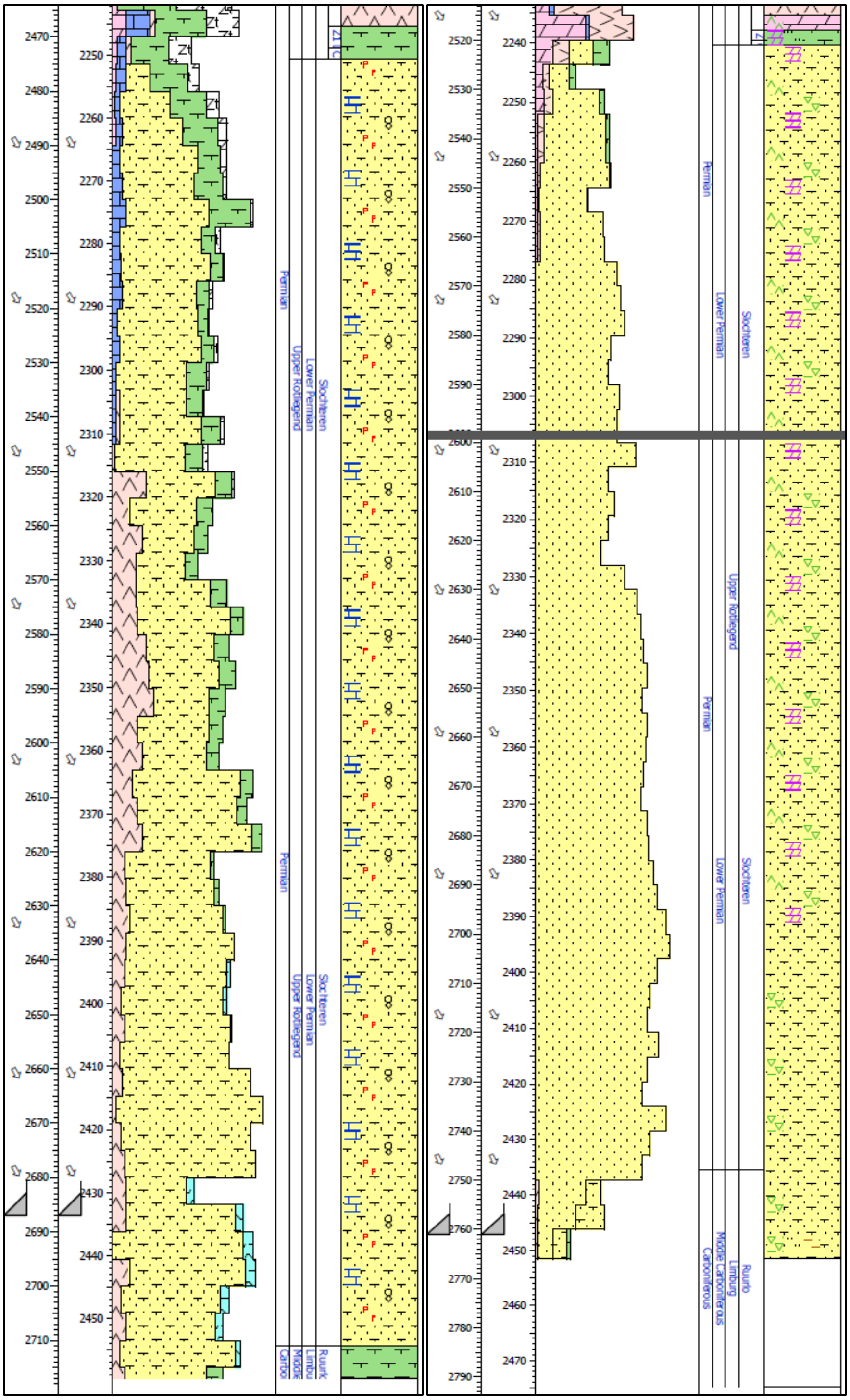

Figure 5.4 Comparison of the lithologs of MDM-GT-03 (left) and MDM-GT-04 (right). The top of the Rotliegend is below the uppermost clay layer at 2475 mAH (left) and 2520 (right)

Figure 5.5 shows a log plot of the Bergermeer-1 well which is located about 30 kilometers southwest of Middenmeer. Deeper than 2200 mTVD (around 2205, 2215, 2235 etc) small peaks in gamma and density and strongly decreased porosity are visible. Shallower than 2200 mTVD, for example between 2145-2147, 2165-2168, 2177-2190 peaks in the density log, low porosity and a flat gamma are observed. This could possibly be similar to the phenomena seen in Kampen and Koekoek-spolder although extreme density variations are absent in Bergermeer. The Bergermeer log pattern has been interpreted as bottom sets of eolian deposits. Figure 5.6 shows an outcrop analog. The bottom sets are poorly sorted and therefore have low porosity / high density, and may be clay rich (high gamma). At shallower depth similar poorly sorted bottom sets are present, without the clay content. A similar pattern was observed in Vermilion wells very close to Middenmeer (pers. comm. Erik Ham).

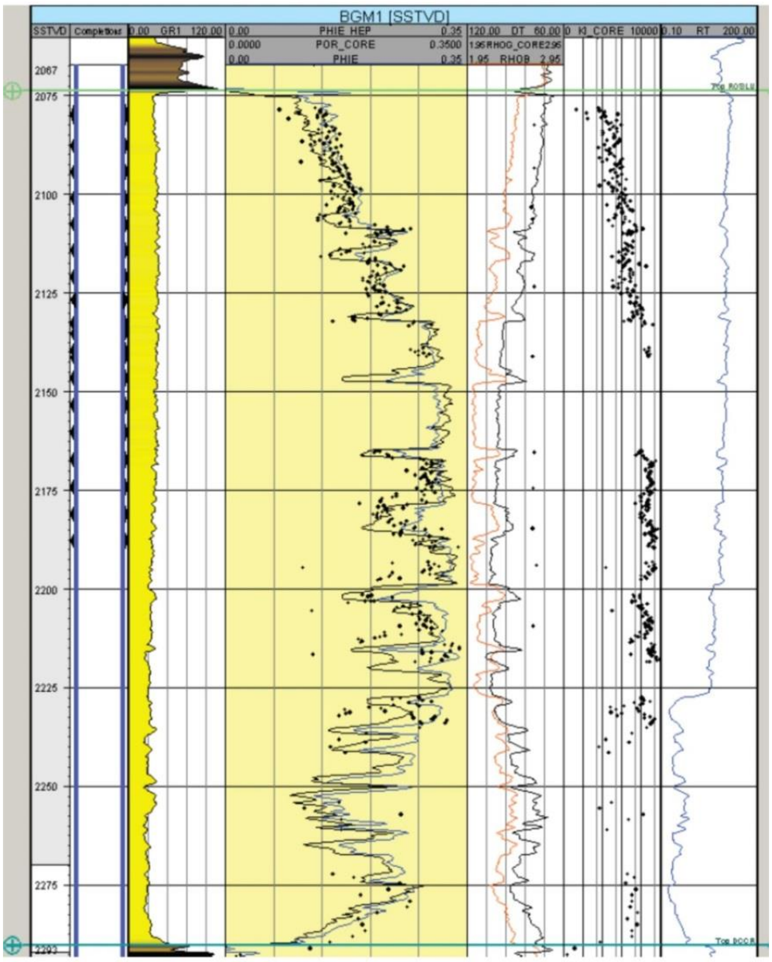

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Figure 5.5 Bergemeer-1 log plot showing low quality reservoir near the top, and various low porosity streaks. Figure Panterra, courtesy Erik Ham.

Figure 5.6 Low porosity streaks interpreted as bottom sets of giant through shaped cross beds sets in the Canyon de Chelly in Arizona. These deposits are considered to be outcrop analog of the Bergermeer wells. Photo Kees Geel.

Formation Water Characteristics

The formation water consists dominantly of Na, Ca, Mg, K, Cl and S, as well as minor amounts of Fe, bicarbonate, Ba, and Sr. The pH yields 5.7 (Source: ECW water samples from Panterra report). To evaluate the saturation stage of the formation water with respect to e.g. carbonates the software PHREEQC (Version v03) was used. At different temperature and pressure conditions as well as pH values the saturation stages e.g. of the minerals calcite ($CaCO_3$), anhydrite ($CaSO_4$), barite ($BaSO_4$), celestite ($SrCO_3$), goethite (FeOOH), hematite (Fe_2O_3), and pyrite (FeS_2) were considered. The results show that only barite shows minor precipitation with $2 \cdot 10^{-5}$ mol/ kilogram of water. Overall the amounts appear to be negligible. The total amount of gases dissolved in the water phase depends on the pressure and temperature conditions at a given salinity. It is assumed that the two phases (water and gas) are in equilibrium and that dissolved amounts of CO_2(g) are reflected by the bicarbonate concentration in the water phase. Degassing of water and the subtraction of CO_2 shifts the equilibrium reaction to the left site resulting in increasing pH to more neutral conditions (Eq. 1).

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \leftrightarrow HCO_3^- + H^+ \leftrightarrow CO_3^{2-} + H^+ \quad (1)$$

Note that degassing processes were not calculated, but they are accounted for in by the changes in pH. It influences the amount of available protons in the PHREEQC calculations.

The sediments are characterized by aeolian deposits with a good reservoir quality. The local permeability ranges between 53 and 115 mD (Panterra 2013, 2015) and porosity yields 14-18%. The sandstones are light-red coloured, fine to medium grained at the top, medium grained in the middle and medium/coarse grained at the bottom. Some claystone, dolomite and anhydrite layers are intercalated (ECW 2014).

The most abundant detrital minerals are quartz, K-feldspar and various rock fragments. Authigenic minerals are comprised by quartz, carbonates, sulphates, clay minerals (illite, chlorite, and kaolinite) and ferric oxides. The grains show coatings on the surfaces, which could act as nucleation sites for mineral precipitation during operation.

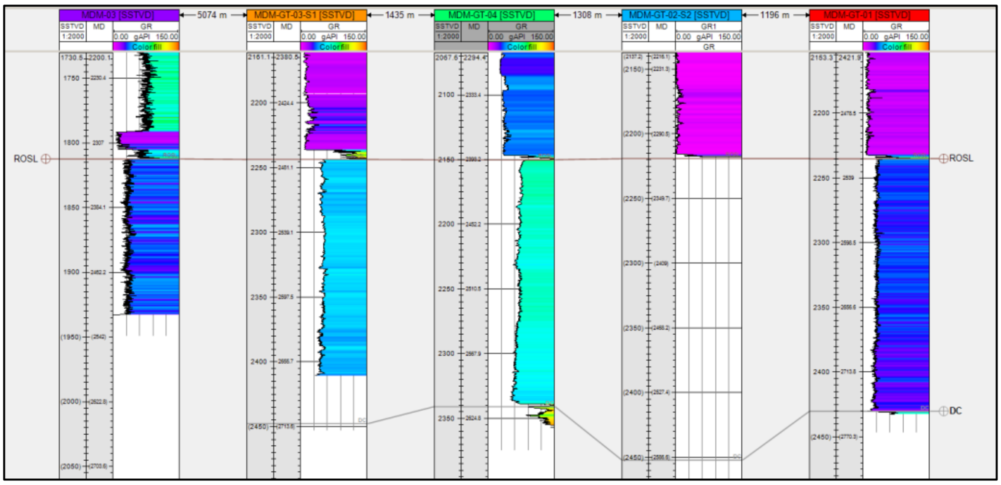

Figure 5.7 Well section of the Middenmeer Concession, showing the low gamma in MDM-03 and MDM-GT-01 on the one hand, and higher gamma in MDM-GT-03 and MDM-GT-04.

Mud cake

Mud cake (or filter cake) is the residue deposited on a permeable medium when a slurry, such as a drilling fluid, is forced against the medium under a pressure. The formation of all filter cake that forms partly inside the formation leads to formation damage (Chemwotei 2011) . Two types of acid treatment can be used to eliminate the positive skin (Barrios et al. 2012):

- Highly concentrated acid mixture (6-8%) and delayed RPHF (Retarded Phosphonic Hydrofluoric) created from Phosphonic acid, hydrochloric and hydrofluoric acid.
- Mud Acid Mixture (HCl:HF) consists of hydrochloric acid and hydrofluoric acid.

Quartz, clay, and feldspars are the main siliceous particles involved in damage of sandstones. The primary chemical reactions in sandstone acidizing are:

Formation damage by scaling products

Although considered unlikely in MDM-GT-03, barite ($BaSO_4$), strontionite ($SrCO_3$) and calciumfluoride (CaF_2), are proposed as scaling potential in MDM-GT 01/02 by the ECW report in scaling and corrosion (ECW; 2014). Barite scaling is predicted by different models to be the most dominant scaling. For MDM-GT-03 the precipitation of barite within the reservoir blocking large pores seems to be unlikely, but apparently as a scaling product it could play a role. Currently, barite scaling is not observed in the filters of the Middenmeer installation.

(GTN 2014): In case scaling occurs, it can seriously effect operations. Especially barite and calciumfluoride scaling, because they are difficult to remove. Barite and calciumfluoride scaling can NOT be cleaned by (simple) acid (or caustic) cleaning. Barite is insoluble in acids and calciumfluoride is near to insoluble in acids. These type of scales have to be mechanically removed and/or with a treatment involving: solubilising with (H)EDTA, complexing with caustic (to form e.g. barium carbonate), acidizing (to dissolve the carbonate formed) and flushing out the acid.

In case of carbonate mineral scaling (very unlikely) such as calcium carbonate ($CaCO_3$), dolomite ($CaMg(CO_3)_2$) or siderite ($FeCO_3$), matrix acidizing can be applied with success. The main HCl-soluble minerals are calcite, dolomite, and siderite which additionally do not generate precipitates.

5.1.3 Applicable soft stimulation techniques

Not all soft stimulation technologies apply because the geothermal system is operational. Weighing easiness of application vs. skin improvement, the primary technology to consider would be acidization. The technique is described in chapter 4.1. In case this technique fails to increase the flow to the desired levels, hydraulic mode-1 stimulation (see chapter 3.2) or radial jetting (see chapter 3.3) can be considered, noting that both technologies are not (yet) readily available or proven in geothermal siliciclastic reservoirs.

Acidization

The parameters taken to design an acid treatment should begin with a deep evaluation of the characteristic of the geothermal reservoir: composition, structure, permeability, porosity, temperature and pressure, and the properties of the reservoir fluids. However, perhaps the most important factor to designing truly effective acidizing treatments is the assessment of the formation damage.

Using the data that were made available (Reports and the DoubletCalc scenario from Panterra) from ECW – see below – calculations were made assuming that the skin is completely reduced to zero.

source	**porosity [-]**	**avg perm [mD]**	**net sand [m]**	**hole ["]**	**deviation [°]**
well test and PVT report ECW MDM GT03 (May 21)	0.16	53	180	6.6	30.5
interference test MDM-GT-01 and -02S2	0.158	60			
MDM-GT-04		95-115			

Table 5.1 Reservoir parameters collected from the reports on the MDM-GT wells

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Geotechnics (Input)

Property	min	median	max
aquifer permeability (mD)	99.0	100.0	101.0
aquifer net to gross (-)	0.97	0.97	0.97
aquifer gross thickness (m)	214.0	215.0	216.0
aquifer top at producer (m TVD)	1940.0	2156.0	2372.0
aquifer top at injector (m TVD)	2026.0	2251.0	2476.0
aquifer water salinity (ppm)	150000.0	165000.0	180000.0

Property	value
number of simulation runs (-)	1000.0
aquifer kh/kv ratio (-)	1.0
surface temperature (°C)	10.0
geothermal gradient (°C/m)	0.0357
[mid aquifer temperature producer (°C)]	0.0
inital aquifer pressure at producer (bar)]	0.0
[initial aquifer pressure at injector (bar)]	0.0
exit temperature heat exchanger (°C)	35.0
distance wells at aquifer level (m)	1335.0
pump system efficiency (-)	0.6
production pump depth (m)	597.0
pump pressure difference (bar)	90.0
outer diameter producer (inch)	8.5
skin producer (-)	7.24
skin due to penetration angle p (-)	-0.13
pipe segment sections p (m AH)	597.0,1314.0,2110.0,2394.0
pipe segment depth p (m TVD)	597.0,1224.0,1918.0,2156.0
pipe inner diameter p (inch)	8.52,12.41,8.68,5.92
pipe roughness p (milli-inch)	4.0,4.0,4.0,4.0
outer diameter injector (inch)	6.6
skin injector (-)	0.73
skin due to penetration angle i (-)	-0.14
pipe segment sections i (m AH)	1156.0,1750.0,2153.0,2474.0
pipe segment depth i (m TVD)	1156.0,1622.0,1972.0,2251.0
pipe inner diameter i (inch)	12.41,8.52,6.37,4.89
pipe roughness i (milli-inch)	4.0,4.0,4.0,4.0

Geotechnics (Output)

Monte Carlo cases (stochastic inputs)	P90	P50	P10
aquifer kH net (Dm)	20.71	20.83	20.96
mass flow (kg/s)	59.97	61.35	62.84
pump volume flow (m³/h)	197.3	202.9	208.7
required pump power (kW)	822.2	845.3	869.7
geothermal power (MW)	10.43	11.54	12.73
COP (kW/kW)	12.6	13.6	14.7
aquifer pressure at producer (bar)	209.58	223.06	236.82
aquifer pressure at injector (bar)	220.14	233.33	246.98
pressure difference at producer (bar)	38.1	38.96	39.9
pressure difference at injector (bar)	45.09	46.15	47.19
aquifer temperature at producer * (°C)	86.56	90.8	95.07
temperature at heat exchanger (°C)	84.73	88.8	92.94

base case (median value inputs)	value
aquifer kH net (Dm)	20.83
mass flow (kg/s)	61.34
pump volume flow (m³/h)	202.8
required pump power (kW)	845.1
geothermal power (MW)	11.53
COP (kW/kW)	13.6
aquifer pressure at producer (bar)	222.95
aquifer pressure at injector (bar)	233.27
pressure difference at producer (bar)	38.96
pressure difference at injector (bar)	46.14
aquifer temperature at producer * (°C)	90.81
temperature at heat exchanger (°C)	88.81
pressure at heat exchanger (bar)	40.33

* @ mid aquifer depth

Figure 5.8 DoubletCalc scenario from Panterra (received from Erik Ham d.d. 15 July 2015)

The reported skin in MDM-GT-03 (injector) in the scenario above is 0.73. If DoubletCalc is run with a skin of zero, there is an increase of performance of 0.3 MW ('geothermal power (MW)').

But the injector is only half of the doublet, so we've also run a scenario with zero skin for MDM-GT-04, the producer well. The reported skin is 7.24. Removing this skin completely would hypothetically improve the geothermal power with 3.0 MW.

Multiple skin factors were reported. The report by Panterra concludes with a skin of -2.3 (negative), accounting for 50% of the perforated interval.

Making adequate assessments of the skin in the wells (both injector and producer) will give better insights in consequent operations to increase the performance.

The application of acidization will increase the transmissivity of the geothermal reservoir:

- It remedies the limitations of the pore spaces (naturally present, or induced/secondary),
- It increases the flow of the presently used reservoirs above their natural capability to support flow, and
- It potentially makes presently unsuitable reservoirs suitable.

Effective Operations of Acidization
As described in chapter 3.1.1, matrix acidizing in geothermal wells is usually conducted in three main steps: pre-flush, main flush and over-flush (Malate, 2003; Portier, André, & Vuataz, 2007). The **pre-flush** displaces the formation brine, after which the **main flush** in a sandstone acid treatment removes the damage and the **over-flush (or post-flush)** in a sandstone acid treatment serves to push the main fluid further away into the formation and minimize inevitable precipitation reactions from taking place near the wellbore.

To get a better understanding of field experience, Karl Gollob (Technisches Büro Karl Gollob GmbH[15]) was interviewed on his view on the execution of an acid job. Below, a summary of his experience is given. The summary is organized from design, via execution, to risks:

The design of an acid job is crucial (e.g. Nitters et al. 2000). Understanding and proper care in the selection of the working fluid, the knowledge of the mineralogy and the boundary conditions (e.g. pressure, temperature, rheology, reactions, etc) are crucial for the success rate of an acid job. Most cases typically refer to a 15% HCl pre-flush, followed by an acid job with 15% HCl in case carbonates are present. In the presence of sand the amount of HCl must be reduced, and 3% HF added. The design of the acid job is a challenge. How must these complexities be dealt with?

According to Karl Gollob, an acid job can only be designed up to a certain level. During the execution of the job the reaction is visualized via the pressure readings and rates. Based on these data a decision is made whether to further soak or make a pressure diversion. These decisions cannot be made in advance. In the De Lier geothermal well both steps were made: first soaking and when it was evident that the acidization was successful, pressure diversion was made. The De Lier wells are the highest producer and best injectors in the Dutch geothermal industry.

When planning the execution of an acid job, it is important to think about the approach carefully.

Karl Gollob stresses that it is crucial to collect as much information as possible. Understand the geological and rock information and be aware what acid will do to the rock. This is very worthwhile, because sometimes even no acid is the best solution and can clean drill in fluid and underreaming solve the issue as well.

When design and selection are done, it is crucial for the assessment of the outcome to know the penetration into the formation. Other projects and reports indicate

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ranges which sum up to penetrations of 0.5 – 5 meters into the reservoir. How far the acid enters the formation, depends on how it is applied.

Karl Gollob indicates that small penetrations into the reservoir can be made with an overbalanced perforation[16]. Those can be in the range of 0.5 – 5 meter, depending on the overbalance pressure. Very common is hydra jetting, which can create nice penetrations.

In order to intensify and steer the outcome, it would be beneficial to know the discriminating factors and key dependencies.

Karl Gollob agrees and states that it is important to know all the facts and find a good solution. In the past there were wells that where candidates for abandonment. In such a case a higher risk can be taken, as it can only be a win win situation. Just a small example: make huff and puff with gas or nitrogen via gas lift installation and then produce the attic oil.

What is the most effective (or most common) way to carry out an acid job after a proper fluid has been selected? In some cases bullheading is considered to be favourable for effective operations.

Karl Gollob dislikes bullheading. If affordable, a big coated tubing is installed down to the target zone. Then, enough force and fluid are used. It is advised to be gentle in the beginning but pump as hard as allowed by the pressure gradients when a reaction is observed.[17]

In chapter 4.1, risks and consequences of acidizing are mentioned. Are there major risks which need to be considered by the geothermal operator, based on experience?

According to Karl Gollob unjustified cost savings are among the highest risks for the operation. Due to cost saving there is no – or hardly any – data collection (e.g. cores, logs, studies). As a result, assessing the question what could help best comes down to mere guessing.

5.1.4 Hydraulic Mode-1 Stimulation

The Rotliegend aquifer offers good potential for geothermal application. However, the potential may be enhanced significantly by hydraulic stimulation. Hydraulic stimulation enlarges the contact surface of the well with the reservoir and thus reduces the reservoir hydraulic resistivity. If natural permeability is virtually absent ('hot dry rock'), hydraulic stimulation can also be used to create permeable pathways to connect injector and producer wells. Tensile fracking in non-critically stressed tectonic environments, representative for large parts of the Netherlands,

[16] To create holes in the liner or casing under conditions in which the hydrostatic pressure inside the casing or liner is greater than the reservoir pressure. When the perforation is made, there will be a tendency for the wellbore fluid to flow into the reservoir formation (Schlumberger Oil Field glossary)

[17] Care should be taken not to inadvertently exceed the fracturing pressure

allows to perform hydraulic stimulation with a low level of seismicity. This paragraph describes the results of a study by Pluymaekers et al. (2013).

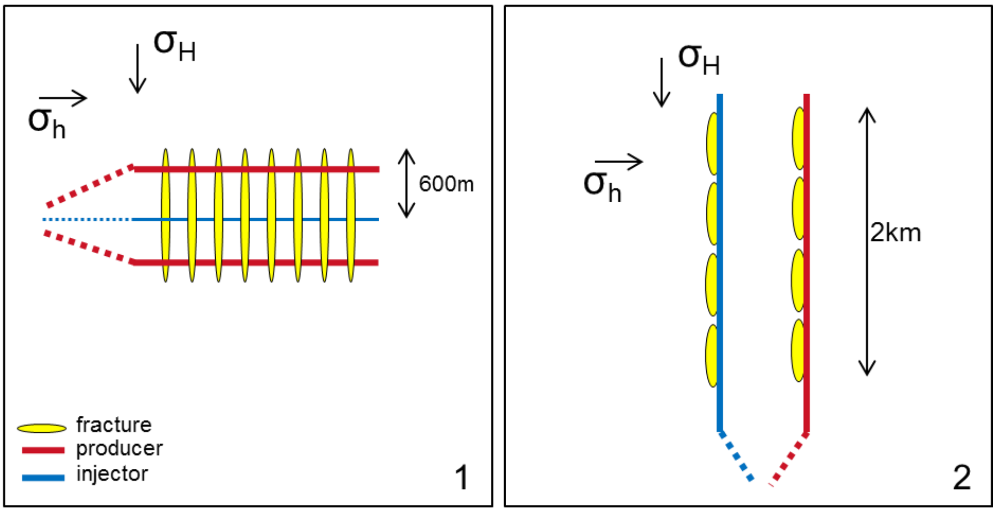

Figure 5.9 Schematic layout of sub-vertical fractures (top view) relative to wells. Scenario 1(left) marked by fractures perpendicular to the well bore is applicable when reservoir transmissivity is extremely low (hot dry rock; <0.5 Dm). Scenario 2 (right) marked by fractures oriented parallel to the fracture well is applicable when the transmissivity exceeds 0.5 Dm (after Pluymaekers et al., 2013).

Potential outcome of Hydraulic Mode-1 Stimulation

The effect of hydraulic stimulation was modelled by assuming a standard well design and fracture approach. For the simulation and well layout long horizontal well trajectories up to 2 kilometers length with vertical fracs along the well bore were assumed ($k_f w$ = 500mDm).

The levelized cost of energy (LCOE) was calculated based on techno-economic performance assessment (Van Wees et al., 2012) using a target coefficient of performance (COP) of 15 for the water loop. In the cost evaluation additional costs for the horizontal well trajectory (as compared to a vertical or slant well) and the costs for stimulation were taken into account as 2 M€ / 500m of horizontal well section.

The implications of being able to tap into existing fracture networks, on subsurface potential are significant as it unlocks considerable clastic aquifer potential. Calculation indicate that hydraulic stimulation is capable of producing higher flow rates – and hence power – than without stimulation with moderate excess in LCOE; extending the potential in depth and spatial extent (Van Wees et al., 2012). The LCOE for the reservoir stimulation scenario can stay well below 12-13 EUR/GJ, depending on natural permeabilities which need to be in excess of 0.5 Darcymeter.

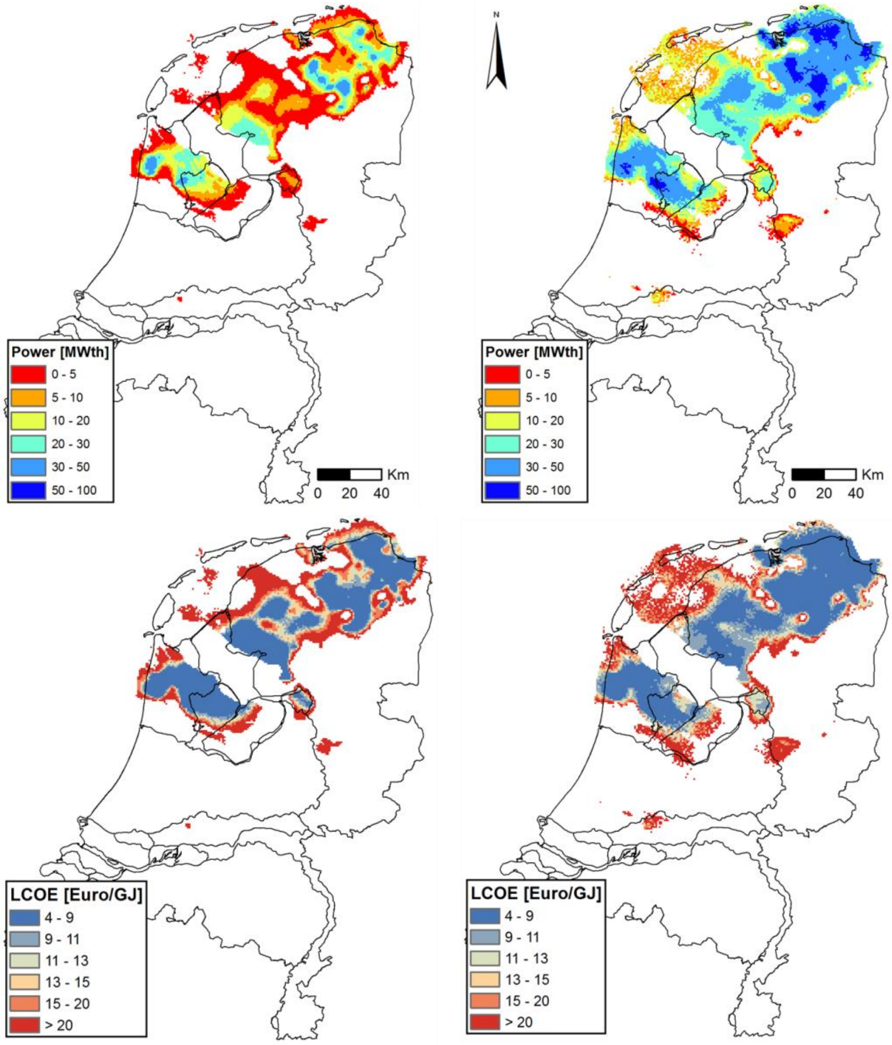

Figure 5.10 Predicted power [MW_{th}] and LCOE [Euro/GJ] without (left) and with standard hydraulic stimulation (right) for a P50 scenario.

5.1.5 *Radial jetting*

The technique of radial jetting is described in chapter 3.3. It is a promising technique for flow enhancement while requiring significantly smaller amounts of water compared to hydraulic stimulation. But like hydraulic mode-1 stimulation, radial jetting was not tested nor demonstrated in siliciclastic (sandy) geothermal reservoirs yet.

Development of the technology aims at improving its applicability and effectiveness and remains ongoing. These developments focus on investigation of the site specific conditions and more sophisticated modelling to get a more accurate estimate of the expected revenues from site specific assessment of the applicability of radial jet drilling. Moreover, further development of the technique is (and will be) pursued in several research programs, among others within the European Horizon2020 framework.

The TNO report on radial drilling (Peters et al., 2015) states that for radial jetting the formation rock needs to have a minimum porosity of about 3-4% to be jettable and the most important criteria for the well are the minimum diameter (about 4 inch) and maximum along hole depth (about 5 kilometers). The Middenmeer concession meets these minimum requirements.

Performance enhancement by Radial Jetting
The increase of performance is – as before in this report – expressed as the skin, but can as well be expressed as the 'productivity improvement factor' (PIF). Figure 5.11 shows the results of radial jetting as a function of the length of the radial and the number of radials:

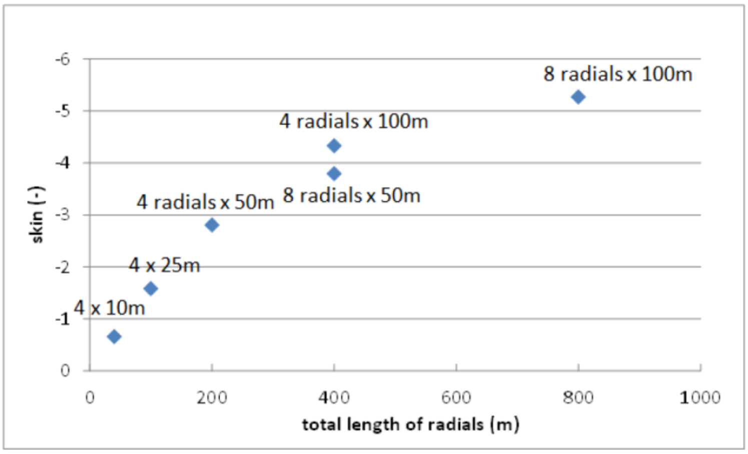

Figure 5.11 Resulting negative skin factors for varying radials configurations

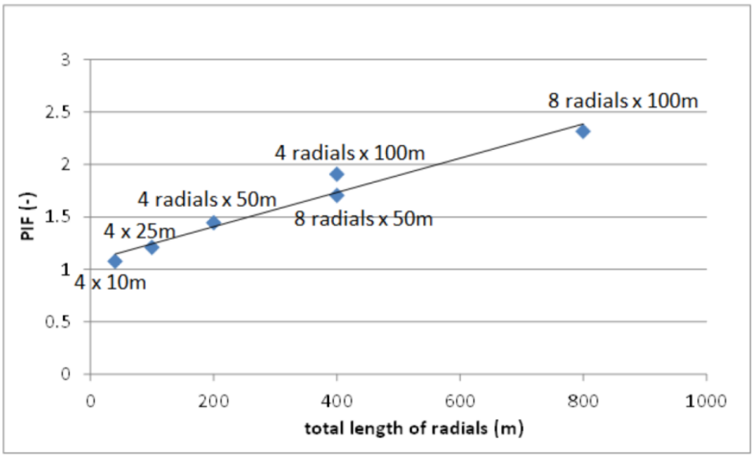

Figure 5.12 PIF for varying radials configurations as a function of the total length (number of radials × the length of a single radial)

The specific skin improvements can be calculated by:

$$skin = a + b\sqrt{\frac{k_h}{k_v}} + cH$$

where a, b and c are radial specific parameters, depending on the well configuration, k_h and k_v are respectively the horizontal and the vertical permeability (mD) and the height H of the reservoir (m) (see Peters et al. 2015). Table 5.2 shows typical values for a, b and c for six radial configurations. Figure 5.13 shows that, if these values are applied for the Rotliegend reservoir, it is possible achieve negative skin values ranging from -0.5 to -5.

number of radials	length [m]	a	b	c
8	100	-7.6072	0.5668	0.0106
8	50	-6.3387	0.5094	0.0125
4	100	-7.1746	0.6097	0.0141
4	50	-5.4982	0.5620	0.0135
4	25	-3.4352	0.3003	0.0101
4	10	-1.6124	0.1520	0.0054

Table 5.2 Values for a, b, c (see Peters et al. 2015)

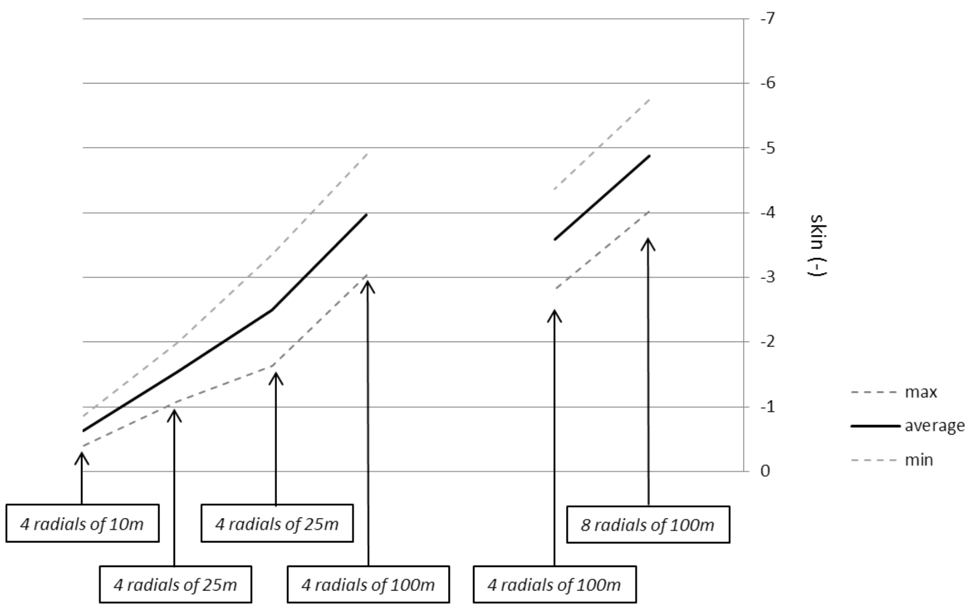

Figure 5.13 Theoretical negative skin factors that can be achieved for Rotliegend reservoirs with a horizontal permeability of 80 to 100 mD and an anisotry ranging from 2 to 20.

5.2 Case Triassic

5.2.1 Problem statement

A new doublet will be drilled in the Naaldwijk concession, probably in 2016 or 2017. After testing the quality of the Jurassic and / or Cretaceous reservoir, the first well will be deepened to the Triassic.

5.2.2 Acidizing

The potential flow rate of a doublet drilled into the Main Buntsandstein in the Naaldwijk concession has been calculated by T&A Survey (2013). In this report attention is also paid to the potential flow rate after stimulation. Information about the susceptibility of the Main Buntsandstein in the area to acid stimulation was derived from the NAM report 'Memorandum SPC/3 no. 653/86 – KDZ-2 Acid response test' (1986). In the latter report, the porosities and permeabilities of nine core plugs both before and after two acid stimulation jobs are presented (Figure 5.18).

Figure 5.14 shows the West Netherlands Basin in the province of Zuid-Holland. The depth of the top of the Detfurth Formation shows various tectonically determined high (depth less than about 3375m) and low structures (depth exceeding about

4000m). Most well information relates to the shallow structures. This makes the relevance of the permeabilities measured in those wells limited for prediction of the permeability on the target location. The well GAG-05 is an exception as it was drilled into the deep block hosting the Maasdijk gas field. Figure 5.15 shows core plug information that was collected from the Main Buntsandstein section in this well. Whereas some plug permeabilities between 10 and 100 mD were measured in the shallow Hardegsen Formation , the overall permeability lies between 0.1 and 10 mD.For the deeper Detfurth and Volpriehausen Formations, the measured permeabilities are between 0.01 and 2 mD. GAG-05 was drilled close to a fault which may have influenced the permeability negatively. Recent information however shows that the more recent well GAG-06, which was drilled in the middle of the block, has an even lower permeability. This is important information because the Naaldwijk concession is located over a similar low structure as the Maasdijk field, and the GAG-05 and GAG-06 wells can be considered equivalents.

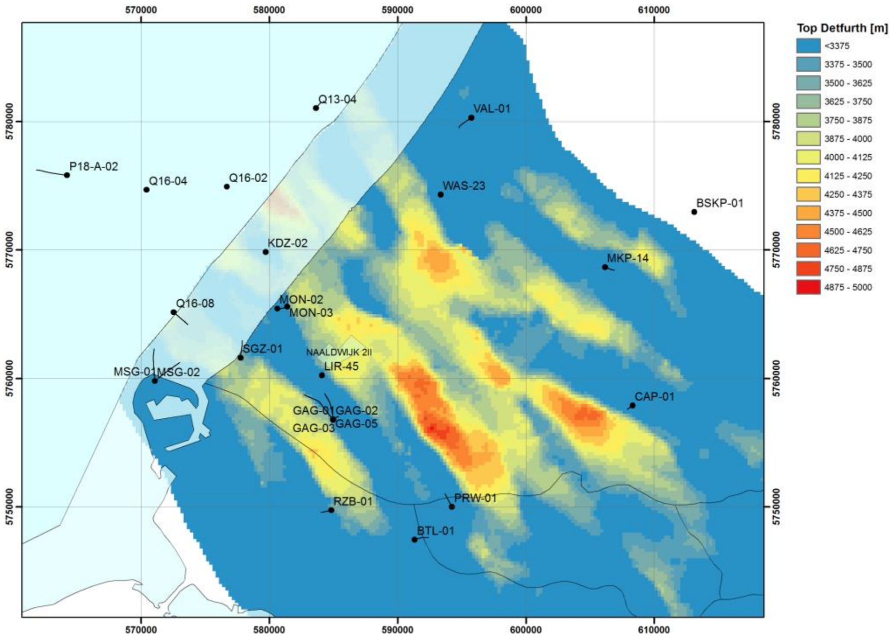

Figure 5.14 Depth of the top of the Detfurth Formation in the West Netherlands basin showing wells addressed in table 7-14 of T&A (2015). Most oil and gas exploration wells were drilled into elevated structures (depicted in blue). The target of the Trias Westland doublet is located in a deep structure.

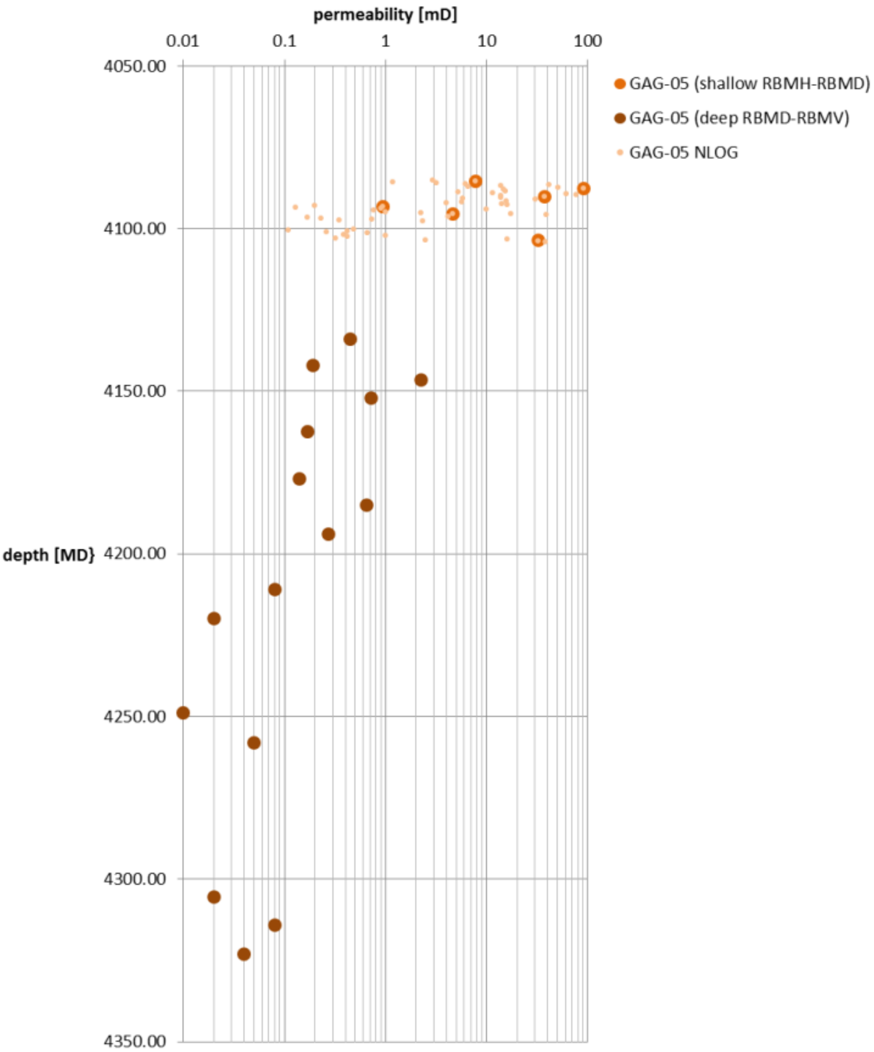

Figure 5.15 Permeability – depth relationship for the important GAG-05 well. RBMH = Hardegsen Formation, RBMD = Detfurth Formation, RBMV = Volpriehausen Formation. Note that in GAG-05 about 70 core plugs were measured (small dots). The large dots are the core plugs described in the NAM report 'GAAG-2A & GAAG-5 wells Sedimentology, petrography and reservoir quality of the Triassic Middle Buntsandstein' (source: NLOG)

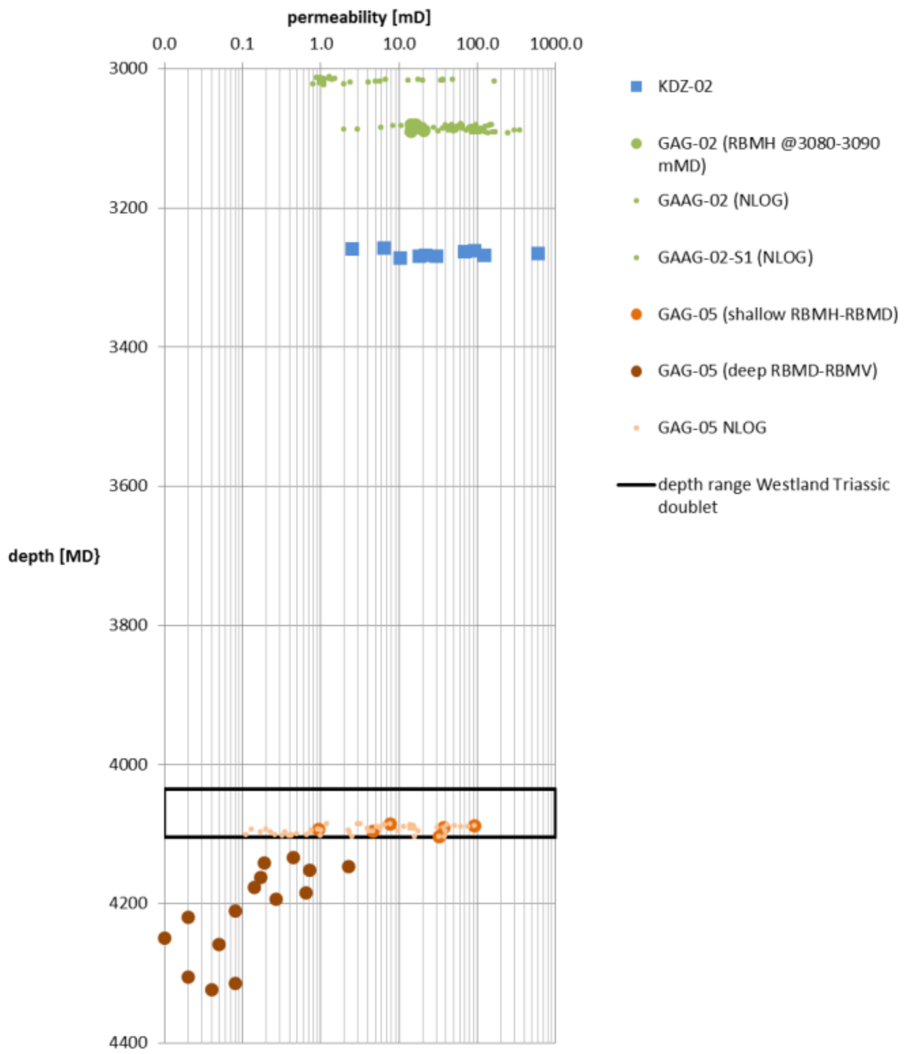

Figure 5.16 Permeability – depth relationship for the wells KDZ-02, GAG-2A and GAG-05 (zoom out from Figure 5.15). The Triassic in the KDZ-02 and GAG-2A wells is significantly shallower than the anticipated depth of the Trias Westland doublet (depth rectangle according to T&A 2013, minimum depth 3823m (i), maximum depth 4119+182m (p)). The average permeability for the GAG-05 plugs is about 2 mD.

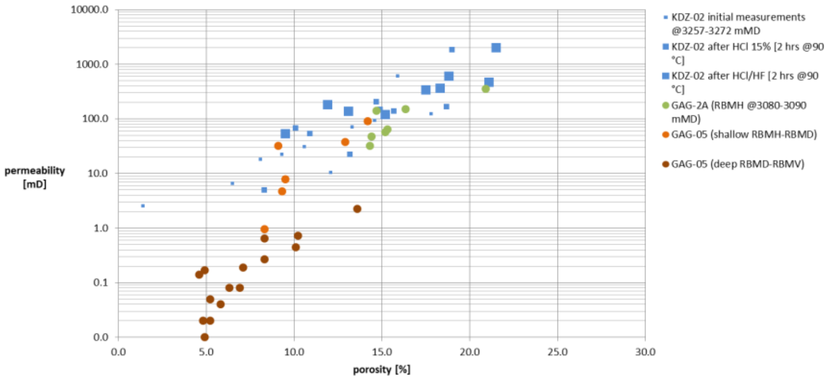

Figure 5.17 Porosity –permeability relationship for core plugs from the KDZ-02, GAG-02 and GAG-05. The deepest core plug data (also shown in Figure 5.15 and Figure 5.16) show the lowest porosities and permeabilities. For the acid stimulated KDZ-02 well, both the unstimulated and stimulated poro-perm data are shown (large squares)

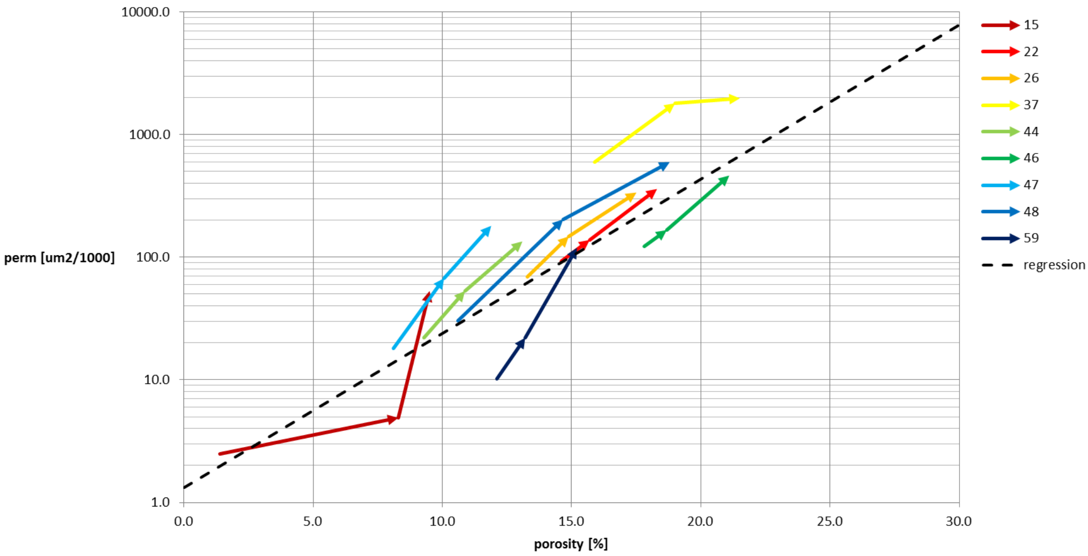

Figure 5.18 Porosity – permeability relationships of the acid stimulated KDZ-02 core plugs (also shown in Figure 5.17). Each colour arrow represents one core plug sample and two stimulation steps (first 15% HCl, second 12% HCl / 3% HF).

Figure 5.18 shows the increase in both porosity and permeability as a result from a two-step acid stimulation of core samples from the nearby KDZ-02 well. The side-track of this well was drilled into the Main Buntsandstein at a depth of

Figure 5.15 - Figure 5.17, in combination with Figure 5.14, suggest that the expected permeability at the Trias Westland target location is likely to be very low, probably in the order of a few mD, as was also reported extensively by TNO (AGE 13-10.026 of July 3rd, 2013). This is in contrast with the suggested permeability ranges 4-15-150 (T&A 2013, table 2.10) and the more recent 1-100-485 (T&A 2015, figuur 2-2). Table 5.3 lists the geothermal power for a number of different scenarios, ex- or including acid stimulation.

source	permeability [mD]	stimulation	P50 power [MW_{th}]
T&A 2013	4-15-150	-	10.2
T&A 2013	4-15-150	acid	18.1
T&A 2015	1-100-485	-	45.8
T&A 2015	1-100-485	acid	64.6
TNO (based on T&A 2015)	1-5-30	-	2.6
TNO (based on T&A 2015)	1-5-30	acid	4.7

Table 5.3 P50 geothermal power as resulting from different choices for (especially) the permeability range. The skin as a result from acidizing taken from T&A (2013, paragraph 2.3.1.1)

5.2.3 *Hydraulic stimulation*

For the feasibility of hydraulic stimulation, the same question as for acid stimulation is important: what is the initial permeability of the reservoir. Next, given the negative skin that can be achieved by hydraulically stimulating the doublet, what will be the required pump pressure, and what will the resulting flow rate (and, as a result, the geothermal power).

Additionally, the direction of the fracs in relation to the orientation of the doublet is important. The major direction of the faults in the Naaldwijk concession is NW-SE, which is approximately the direction of the largest principal stress σ_1. The total depth (TD) locations of the two planned wells are between two such faults. The direction of the major stress implies that a hydraulic fracture will extend from one well in the direction of the other. Given the proposed well distance and small (?) lengths of the fracs relative to the well distance, this could shorten the thermal breakthrough time.

Appendix 3 of T&A (2015) provides details of the planned fractures. The reservoir height (180m) is considered too large for a single fracture, hence a top and a bottom frac are suggested. Both were modelled in the standard software MFrac. From the fracture properties, an equivalent negative skin can be calculated.

Appendix 3 is not entirely clear though. Different fracture dimensions are presented. In part, this is related to the difference between *fracture half-length* and *propped fracture half length*. MFrac differentiates between the total length that is created, and the part of the total length filled with proppant. The latter is relevant for flow. MFrac assumes that the un-propped parts of the fracture will be closed after the stimulation.

- The modelled bottom fracture shown on page 10 of the Appendix has length x height of about 72x120m. The propped dimensions are 57x104m. On page 13, however, the propped half-length is 187m. This value was used for the calculation of the negative skin factor. This is over three times the value of the modelled fracture. If the true propped half-length is 57m, the skin factor is estimated too negative.
- For the top fracture, the values are 84x60 and 84x50m, respectively on page 12. This would mean that the propped half-length equals the un-propped half length. On p14, the value of the propped half-length is 272m, which is again more than three times more than the modelled half length.

- The open hole wellbore radius is listed as 0.27 ft (p13, p14), or 3.24". This implies a diameter of 6.48", which is neither what is presented elsewhere in T&A (2013, 8.5") nor T&A (2015, 5.5").

Source	**permeability [mD]**	**well diameter in reservoir ["]**	**Stimulation**	**P50 power [MW_{th}]**	**Flow rate [m^3/hr]**	**Pump pressure [bar]**
T&A 2013	4-15-150	8.5"	frac (skin -5.5)	28	225	135
T&A 2013	4-15-150	8.5"	frac (skin -7)	49	388	135
T&A 2015	1-100-485	5.5"	frac (skin -5.5)	68	548	130
T&A 2015	1-100-485	5.5"	frac (skin -5.5)	76	618	130
TNO (based on T&A 2015)	1-5-30	5.5"	frac (skin -5.5)	7.7	70	130
TNO (based on T&A 2015)	1-5-30	5.5"	frac (skin -7)	14	121	130

Table 5.4 Selected DoubletCalc results for different scenarios for (especially) the permeability range. The skin as a result from hydraulic fracturing taken from T&A (2013, appendix 3). Scenarios in grey based on T&A (2015), negative skin added by TNO.

Table 5.4 shows the results of applying a negative skin as a result of hydraulic fracturing. The equivalent skin factors calculated in T&A (2013) are -5.32 and -5.64 for a bottom and top fracture respectively. In order to be applicable in DoubletCalc, the skins must be combined into a single equivalent negative skin. This is not trivial as the two fracs influence each other. The amount of influence is determined by reservoir conditions like the permeability, and the presence and characteristics of impermeable layers between the fracs. This requires an amount of study which is beyond the scope of this project. The combined equivalent negative skin is less than the sum of the individual skins. In practice, the maximum value for negative skin is in the order of -4 to -5. Larger (negative) skins are theoretically possible but are generally not achieved.

Table 5.4 also shows that applying a fracture significantly increases the geothermal power if the initial permeability is 15 mD or higher. If however the initial permeability is as low as suggested by the GAG-05 and GAG-06 wells, the resulting geothermal power remains modest.

DoubletCalc2D[18] is a software tool developed recently by TNO. It allows to calculate the achieved flow rate of a doublet through time, and the pressure and temperature field development in time. Input for the tool are a simple doublet configuration, and either fixed values for the reservoir properties (depth, permeability, etc.), or, alternatively, grids allowing spatial variation of those parameters.

A number of DoubletCalc2D scenarios was run in order to assess the resulting flow rate given a reservoir and doublet configuration. Reservoir parameters were mostly adopted from T&A (2013). The skin was set to -1 (to account for the probable slant of the well) and -5 (for a stimulated case). A pressure constraint of 130 bar was

[18] http://thermogis.nl/DoubletCalc2D.html

imposed. In order to mimic the geology non-permeable border faults running NW-SE were added to the permeability map.

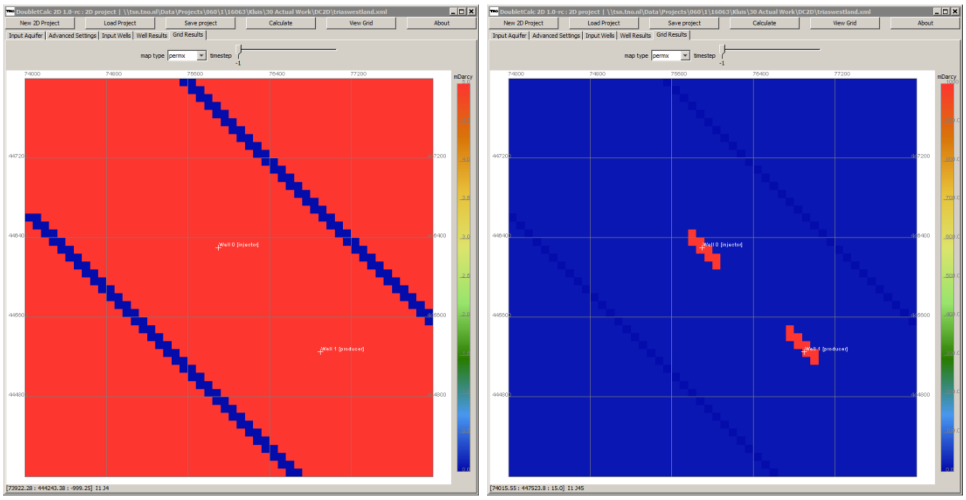

Figure 5.19 Permeability grids showing the locations of producer and injector, and the non-permeable boundary faults having a permeability of 0.1 mD (left). The matrix permeability was varied between 5, 15 and 100 mD. On the right, fractures were added. Cell size 80m. Note the difference in colour scale range between the left and right images.

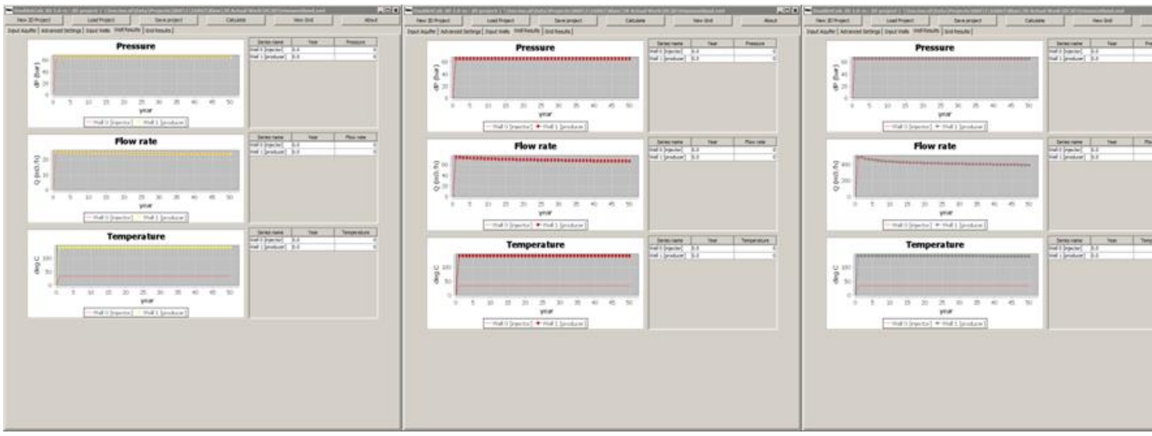

Figure 5.20 Well results for three permeability cases (from left to right 5, 15 and 100 mD). The skin is -1. At the given pressure difference constraint, the flow rate varies from about 25 and 70 to over 400 m³/hr. None of the cases shows cold front breakthrough during the modelled time frame. Especially the 100 mD case shows a decline in flow rate. This is due to the imposed pressure constraint in combination with the development of a cold plume.

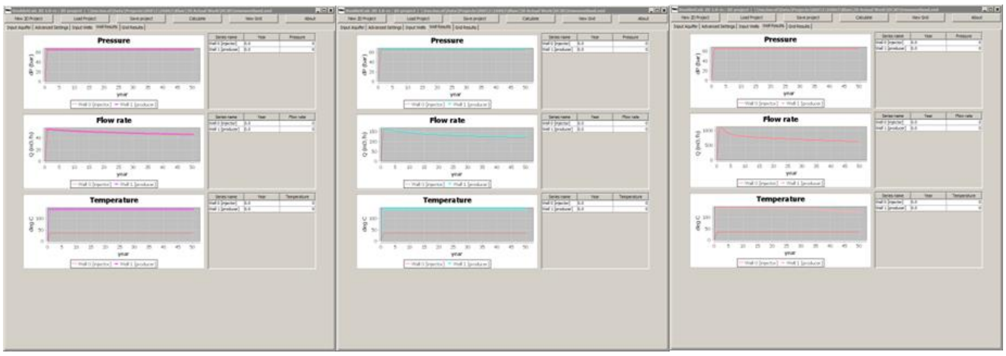

Figure 5.21 Well results for three permeability cases (from left to right 5, 15 and 100 mD). The skin is -5. At the given pressure difference constraint, the flow rate varies from about 50 and 150 to over 1000 m³/hr. Cold front breakthrough is observed for the 100 mD case after about 25-30 years. All cases show a decline in flow rate.

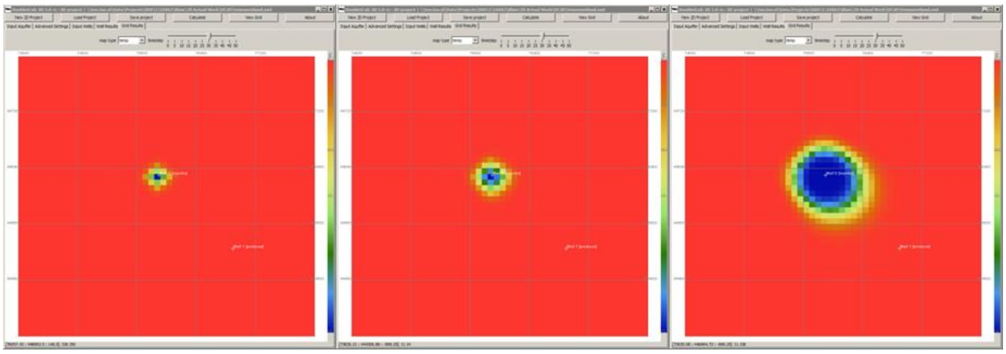

Figure 5.22 Temperature field after 30 years of production for three permeability cases (5, 15 and 100 mD from left to right). Skin -1. The cold front is dominantly circular.

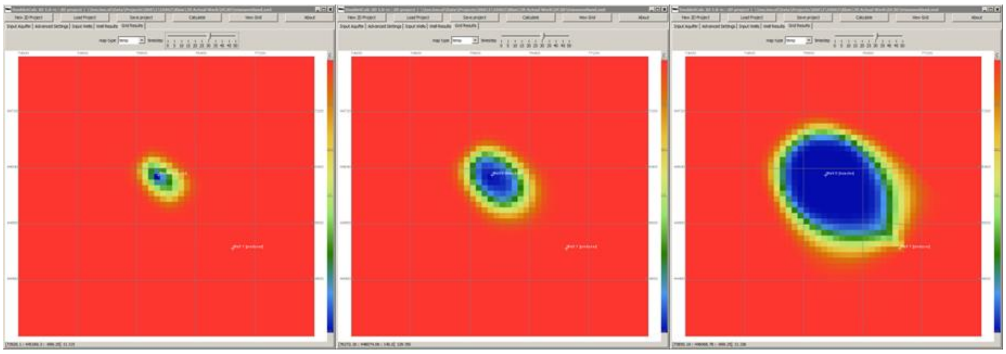

Figure 5.23 Temperature field after 30 years of production for three permeability cases (5, 15 and 100 mD from left to right), with the high-perm frac (see right half Figure 5.19). Skin -1.The fracs serve as a conduit if the fracture transmissivity is higher than the reservoir transmissivity, thereby changing the shape of the originally round thermal front to an ellipse. The cold front breakthrough is accelerated.

It should be noted that hydraulic fracturing does not always result in an increased flow rate. Exact numbers for success rates, either economical or technical, are scarce. In the Shale Gas Plays in the United States, five out of six jobs are successful. The E&P industry uses a pre-job 75-90% success ratio. The E&P industry in Germany supposedly has a 100% success ratio. The fracturing of the GAG-05 well was not successful. Also, there is a chance of leakoff when the second fracture is initiated. If a success rate of 90% is assumed for a single fracture, the success rate of three subsequent fractures would be 90^3% ≈ 74% in case the fractures would not interfere.

5.2.4 Horizontal well

T&A Survey (2013) discusses the possibility of drilling a horizontal well. A comparison is made between the productivity indices of a vertical well with two fractures (as described in the previous paragraph), and a horizontal well with one, two or three fractures. The PI of a horizontal well can be calculated in various ways. Some are described in the memorandum TNO AGE (2014). Among them is the well-known analytical solution by Joshi (1988). The latter method is also applied in the report by T&A Survey (2013). In this document it is further stated that 'the calculation for a negative skin as in non-horizontal wells is not applicable for horizontal wells'. The meaning of the skin factors listed in T&A Survey's table 2.9 is therefore not entirely clear.

An Excel tool made by TNO and available from www.nlog.nl allows the calculation of an 'equivalent skin' for a horizontal well. This is the skin a hypothetical fully penetrating vertical well would have in order to achieve the same productivity index as a horizontal well. For a 180 meter thick reservoir, the skin factors are positive, especially for short horizontal wells and anisotropic reservoirs (Figure 5.24). This indicates that, due to the approximately even ratio between the reservoir thickness and the length of the horizontal well, the added value of having an (unstimulated) horizontal well is very limited. A negative skin will only result if the length of the horizontal well is (much) longer than the reservoir thickness.

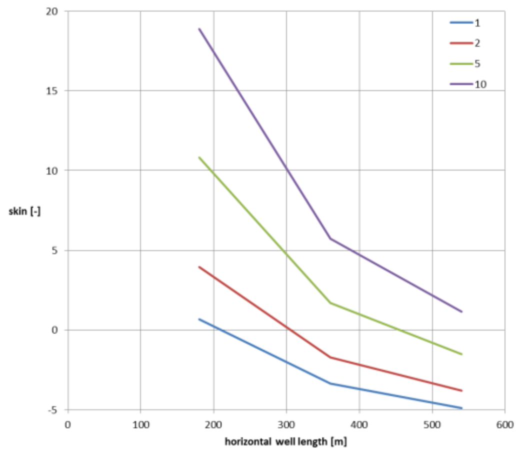

Figure 5.24 Equivalent skin factor for various combinations of an unstimulated horizontal well length and anisotropy k_h/k_v. A short horizontal well is as efficient as a vertical well for $k_h/k_v = 1$ (skin = 0). Long horizontal wells have increasingly negative skin factors. Anisotropy plays an important role.

The anisotropy (defined here as k_h/k_v) also plays an important role. A relatively low vertical permeability (resulting in a high anisotropy value) impedes vertical flow towards the horizontal well, thereby decreasing its effectiveness. When horizontal flow is dominant due to the occurrence of barriers to vertical flow, a vertical well is more effective than an (unstimulated) horizontal well.

The anisotropy of a formation on a reservoir scale cannot measured directly. Core plug anisotropies for the Triassic Volpriehausen Formation, collected from www.nlog.nl, show anisotropies around 1.8 – 3 (Figure 5.25). Core plug anisotropy however cannot be used directly as a measure for reservoir anisotropy due to the difference in scale.

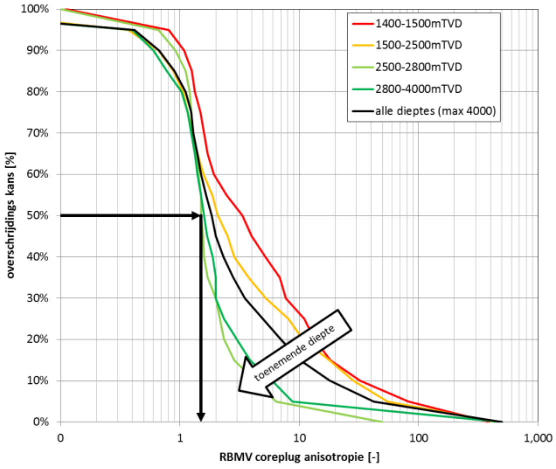

Figure 5.25 Volpriehausen core plug anisotropy. Core plug anisotropies are generally low.

Often, in reservoir modelling the anisotropy is used as 'fudge factor' for achieving a good history match. Typical anisotropy values are between 2 (for a very clean sand) and 1000 (for very laminated reservoirs). Begg, Chang and Haldorsen (1985) present a method for estimating the reservoir anisotropy using the average horizontal permeability, core plug anisotropies, and estimates for vertical flow barrier. Using this method, anisotropies in the order of 10-100 are calculated. This method is very susceptible, however, for estimates on the number of shale layers present that effectively hamper vertical flow. For relatively clean sands, the anisotropy may still be in the order of 5-10. In combination with the relatively thick Triassic reservoir, this would make even a relatively long horizontal well less effective than a fully penetrating vertical well (Figure 5.24).

Stimulation of a horizontal well may be a promising option if the anisotropy is low. A vertical fracture will bypass bed-parallel permeability barriers. Hydraulic fractures will develop in a NW-SE direction. Therefore basically two options exist for the well-fracture configuration: NE-SW (perpendicular to the fracture orientation) or NW-SE (parallel to the fracture orientation) horizontal wells. The latter option dictates that the fractures will be oriented in extension of each other. This also means that when the second and/or third fractures are initiated, care should be taken that the fracture fluid will not be pumped into the already existing fracture(s). Also, the fractures should not grow too large in order not to short-circuit the doublet.

6 Step-by-step approach for a geothermal operator

When considering to stimulate a well, either before or after drilling, a good preparation will increase the quality of the outcome. The most important questions which need to be asked before selecting and designing the stimulation of a geothermal system are listed below.

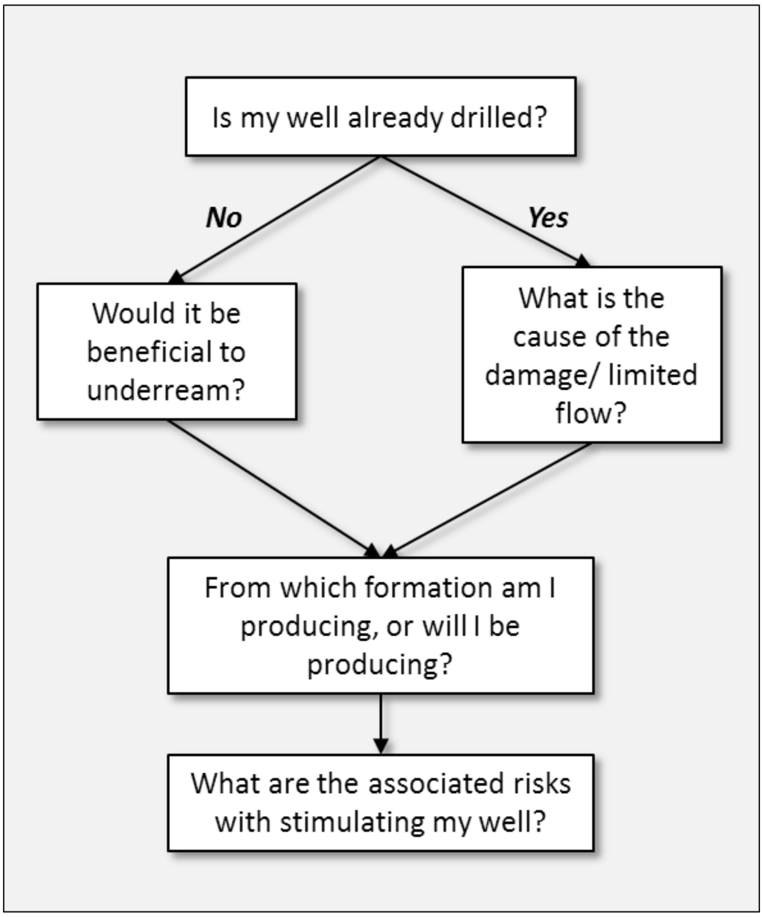

Figure 6.1 First order flowchart for the selection of a stimulation option.

If the well has not been drilled yet, the selection and design of the optimal stimulation technology can be accommodated upfront in the well design, thereby possibly saving resources. The first question could be whether or not underreaming should be considered (see 3.3.3).

If the well has already been drilled, the limiting factor(s) causing the low flow rate must be determined:

6.1 What is the cause of the damage/ limited flow?

The flow rate may be insufficient right from the start, or start to decline during production.

1. immediate low production rate (lower than expected on the basis of the pre-drill estimate, or well log data): the well may be damaged due to insufficient cleaning. This hypothesis is supported if the well test evaluation concludes positive skin and high reservoir permeability.
2. immediate low production rate (lower than expected on the basis of the pre-drill estimate, or well log data): the reservoir quality may be low. This hypothesis is supported if the well test evaluation concludes (near) zero skin and low reservoir permeability.
3. declining production rate: the original reservoir quality is good and the original well skin is (near) zero. The productivity / injectivity of the near wellbore area of the reservoir is deteriorating due to scaling, or is being clogged by mobilized particles. An increasing PI / II (for instance visualised in a Hall plot) is indicative.

(If the production rate is low and in line with the pre-drill expectation, stimulation is required for sufficient flow anyway)

In case of 1 (damaged well) a service company should be contacted in order to inquire about the cause the problem; what materials, used during drilling, may not have been properly removed after drilling. As this is merely a consultancy/warranty related question, it is out of scope for this study.

In case of 2 (poor reservoir quality) the reservoir should be stimulated. The optimal stimulation is dictated by the reservoir composition, diagenetic history and stress state.

In case of 3. (damaged reservoir) the cause of the flow deterioration should be determined. This may have its origin in the fluids that are used and have penetrated the reservoir, dissolution/mobilization/precipitation of particles (fines) from the reservoir, or cementation filling the pore space. This information can be gained from the pre-drill geological research, investigations of core material and cuttings, wireline/ borehole measurements and/or the drilling reports[19].

6.2 Reservoir characteristics of the productive formation

Most stimulation technologies and their practical design are dependent on the geological conditions. Before selecting a stimulation technology, the reservoir should be assessed using the questions below:

[19] When going through the (daily) drilling reports, keep a look out for reports on encountered (total) losses, drill problems, stood ups, clay balling, mud used, etc.

- What are the regional (based on nearby wells) and local (using cores and/or cuttings from the current geothermal wells) geological reservoir characteristics (net to gross, porosity, permeability, rock and brine chemistry)?
- What are the mechanical and physical characteristics of the reservoir (e.g. stress field, brittleness index, pore pressure, fracture density, etc.)?
- Should the burial / uplift history (diagenesis) be accounted for?

6.2.1 Geological characteristics

A poor doublet performance may be caused by a general poor reservoir quality (net to gross, porosity, permeability).

In order to understand the flow behaviour of injected and produced water basic knowledge about porosity and permeability of the storage compartment is indispensable. Different reservoir characterization techniques can be used to characterize these values on different scales.

Reservoir scale: depositional environments

Different depositional environments have different geometries and distribution of lithofacies.

Log scale: flow units and diagenesis of the reservoir

Flow units are described as portions of the reservoir within which the geologic and petrophysical properties that affect the fluid flow vary. Flow units are identified on the basis of a combination of properties such as lithology or lithofacies, pore types and petrophysical data from well logs.

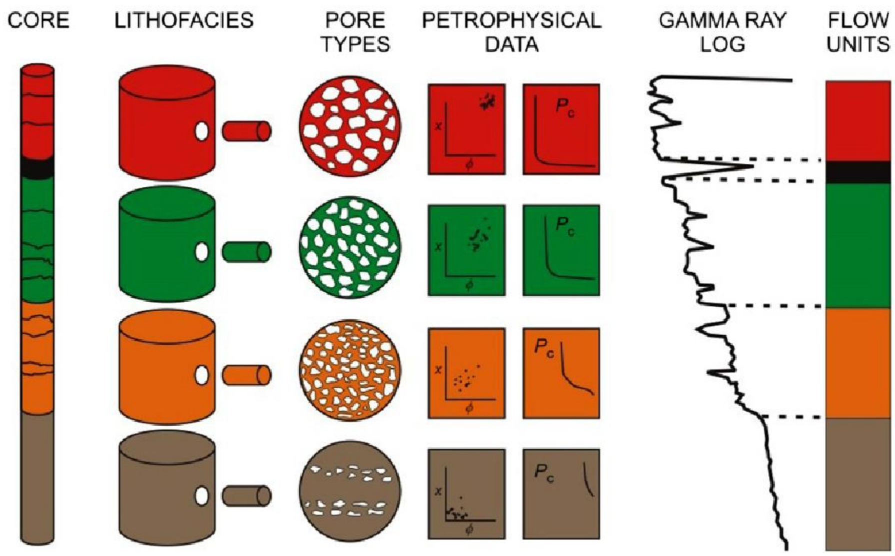

Figure 6.2 Rock properties to classify flow units as defined by Ebanks et al. (1992).

The lithofacies refers to the prime physical (or lithological) properties of a rock being the basic unit for the interpretation of depositional environments. Examples of several types of lithofacies are shown in Figure 6.2. It is important to understand that different lithofacies have different impacts on the quality of the reservoir quality. For instance, better reservoir properties are generally expected in a sandstone than in mudstones or anhydrites. Figure 6.3 shows various flow units in the Kampen and Koekoekspolder wells, having a severe imprint on porosity and permeability. The cause of the low flow rate encountered in the Koekoekspolder doublet was not related to a general poor reservoir quality, but especially due to the extremely low permeability of the anhydrite zones.

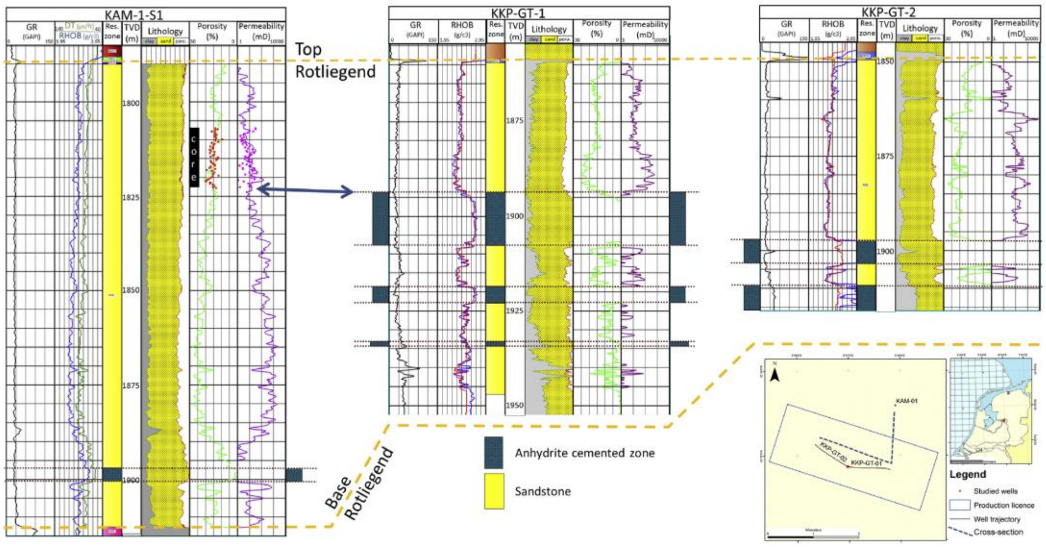

Figure 6.3 Correlation panel of the Kampen and Koekoekspolder wells showing different flow units (sand vs. anhydrite), having different expressions in the gamma ray (GR) and density (RHOB) logs. After Henares et al. (2014).

Core scale
Generally, there is a positive linear correlation between porosity and the logarithm of the permeability. A porous rock can however have low permeability if the pores are poorly connected, for instance when the pore throats are blocked by cement. Similarly, a non-porous rock can be permeable if enough fractures are present.

Thin section scale
After deposition of a sediment, physical and chemical processes are leading towards mineral dissolution and precipitation reactions, thereby changing the rock composition over time. Different mineral reactions may occur in relation to the initial rock composition, the influx of formation water and hydrocarbons during burial, as well as the pressure and temperature development. For example, the precipitation of carbonates, sulphates, or clay minerals may change the porosity and permeability. Figure 6.4 shows examples of porosity and permeability reducing minerals anhydrite and kaolinite.

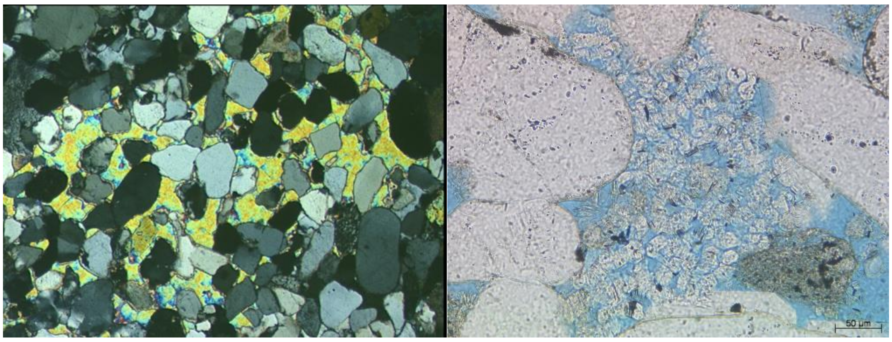

Figure 6.4 Thin section images of different Rotliegend sandstones. Left: anhydrite (yellow and orange) surrounding detrital grains like quartz and feldspar (grey). Right: authigenic kaolinite (small grey) in the pore space between detrital quartz grains (large grey).

The precipitation of minerals is mainly controlled by the physical and chemical conditions and the availability of elements in the water phase. However, especially the temperature may have a significant influence on such reactions. Depending on the geographical location the burial depth and corresponding temperature vary.

Knowledge about the burial history and corresponding pressure and temperature development is very useful in order to predict the present rock composition of the target horizon.

6.2.2 *Mechanical and physical properties of the reservoir rock*

Better knowledge of the mechanical properties allows to better forecast how rocks will respond during hydraulic stimulation or when drilled, for instance when jetting radials.

Mechanical properties can be inferred from lab experiments (triaxial tests, indentation, scratch experiments). Parameters such as porosity, permeability, brittleness index, etc. that can be measured in the laboratory are used to numerically simulate stimulation strategies (either acidization or hydraulic fracturing) and can help to refine well log interpretations. In the context of hydraulic fracturing (see paragraph 3.2), knowledge about the stiffness of the rock can help to better forecast the effect of proppant embedment over time, that is, the expected fracture closure over time.

Acid spreading and fracture propagation are intimately linked to the prior stress and pore pressure field and pre-existing fracture spatial density (i.e., the amount of fractures present per unit volume of rock). For example, the presence of permeable fractures can either “steal” the acids and impair the spreading of the acid treatment (see paragraph 3.1), or act as a barrier to the fracture propagation during hydraulic stimulation. Similarly, zones of high permeability can act as leakoff zones, preventing the pressure buildup required for initiating a hydraulic fracture. Knowledge on the prior differential stress and pore pressure field are also of importance to avoid re-activating in shear pre-existing fractures (see paragraph 3.2).

6.2.3 *Burial and uplift*

The continental sediments of the Rotliegend and Triassic formations (chapter 4) were deposited at surface level. Later they became buried by younger sediments. This reduced the porosity and permeability by compaction and diagenetic processes. Often, there is a clear relation between depth and porosity. Some parts of the Netherlands, notably the West Netherlands Basin during the Late Cretaceous, were first buried deeply, while in a later stage parts were uplifted again (e.g., Nelskamp and Verweij 2012). In such a case, the relation between current depth and porosity is complex. In general terms, the porosity will be lower than expected for the given depth. As basins such as the West Netherlands are usually heavily faulted, differences in burial history will exist from one block to another.

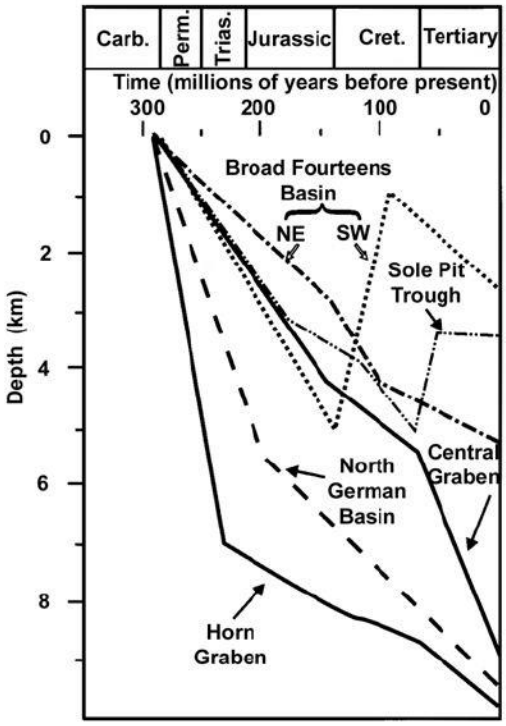

Figure 6.5 Burial history curves for the top Westphalian source rocks of northwest Europe. The Broad Fourteens Basin and the Sole Pit Through were uplifted during Cretaceous and Tertiary times, while the Central Graben, North German Basin and Horn Graben are currently at maximum burial depth. The Broad Fourteens Basin is the north-western extension of the West Netherlands Basin. After Ziegler (2006). For structural elements, see Figure 6.6.

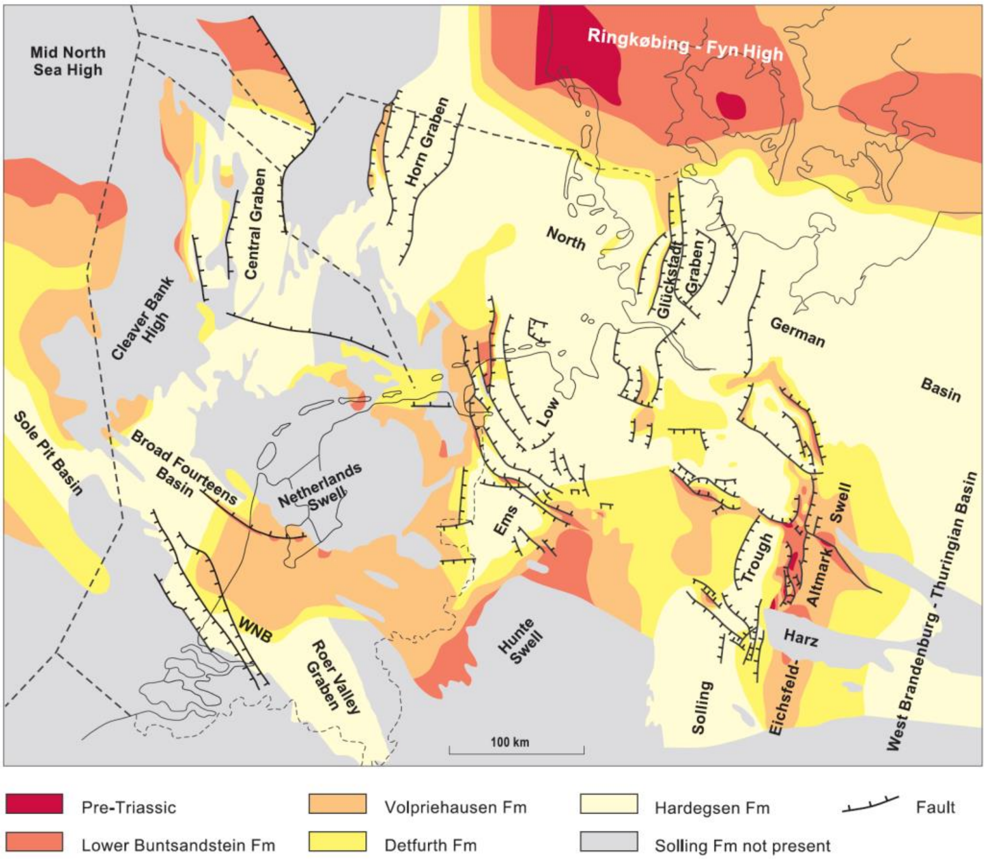

Figure 6.6 Base Solling subcrop map showing main structural elements (Geluk 2007)

In order to predict the current rock characteristics, knowledge about the burial history and corresponding pressure and temperature development is very useful.

In short, knowledge on a *basin and reservoir scale* provides general information on a regional scale about the sediment types and sedimentary body architectures that can be expected. This determines whether certain local rock conditions are likely to be valid elsewhere too. Information on *log scale* provides information on a local scale about the lithology and rock properties encountered at the concession, and its vertical continuity. In combination with log information of surrounding wells, information about the regional lateral continuity can be obtained. Information on a *core scale* provides more detailed information about lithology and rock properties. Finally, information on *thin section* scale provides information about the mineral composition (geochemistry) and diagenetic history of the rocks.

Porosity and permeability are by far the most important type of information to be obtained prior to selecting any stimulation option. Next, if acidization is considered the geochemistry is relevant . This comes down to the question which minerals are present where, if they can be dissolved using the right kind and dosing of acid. When methods like hydraulic fracturing or radial jetting are considered, the geomechanical properties of the rocks (strength, presence of fractures, etc.) and the state of stress are more relevant.

6.3 Risks and Consequences

For any stimulation technique, there is a chance that it will fail. Failure can be defined in technical or economical terms. An *economic* success means that a significant increase in flow rate is achieved. A *technical* success simply means that a fracture has been created, or that a certain amount of pore blocking minerals has been dissolved, without referring to the productivity or injectivity improvement.

Failure may even result in the effect of a stimulation operation being adverse. This means that either the flow rate decreased, or that negative side effects overshadow the success of the increased flow rate.

6.3.1 Failure

Failure is usually the result of poor job design. For hydraulic fracturing, this may be caused by insufficient knowledge of the reservoir, use of unsuitable fluids or proppants, or unsuitably applied pressures. For acidizing, an inappropriate choice of acids (driven by poor knowledge of the reservoir chemistry and / or diagenetic history), an incorrect sequence and/or dose of acids, or unsuitably applied pressures may lead to failure. Acid injection pressures above the fracturing pressure may induce new fractures, leading to acid leakoff and poor performance.

6.3.2 Negative side effects

For hydraulic stimulation, negative side effects may especially include induced seismicity (which, theoretically, do not occur for mode-1 stimulation).

For acidizing, negative side effects may include the loss of reservoir integrity (when the cement that is holding the grains making up the reservoir framework is dissolved), leading to increased sand or fines production. Disturbance of the chemistry of the reservoir may lead to precipitation of minerals, blocking pore throats.

Regarding radial jetting, limited experience is available from both the oil and gas and the geothermal industry. In 2016, the project SURE will start (see chapter 8). This project aims at investigating and developing radials for geothermal projects.

6.3.3 Sustainability

The effective lifetime of a stimulation job result is limited. Evidence from the oil and gas industry is scarce. However it appears that, due to cracking of proppants, washing proppants out of the fracture, or deformation of the reservoir rock, the positive effect of a hydraulic fracture in gas shales lasts for only about 5 years (Jarvie et al. 2007, Figure 6.7). The production behaviour of shale gas wells however may not be representative to geothermal wells. A geothermal well that was hydraulically stimulated in Rotliegend rocks in Gross Schönebeck, Germany, initially had a fivefold increase in production, but the productivity quickly decreased afterwards[20]. Similarly, when the productivity of a well decreases due to scale

[20] Regenspurg et al. (2010, 2015) describe the production of NORM among which Ra and Pb, and of Cu, probably originating from Permian volcanic rocks, in the Gross Schönebeck EGS, which produces from the Rotliegend. Stimulation of the reservoir may lead to increased NORM production.

formation, acidizing needs to be repeated on a regular basis. An example from Denmark showed that regular acid jobs were needed to restore injectivity after periods of summer shutdown. The first few jobs completely restored injectivity, but the latest ones failed to do so. Removal of well damage caused by improper cleaning only needs to be carried out once, but if the well is damaged by fines migration during production, this also requires regular cleaning.

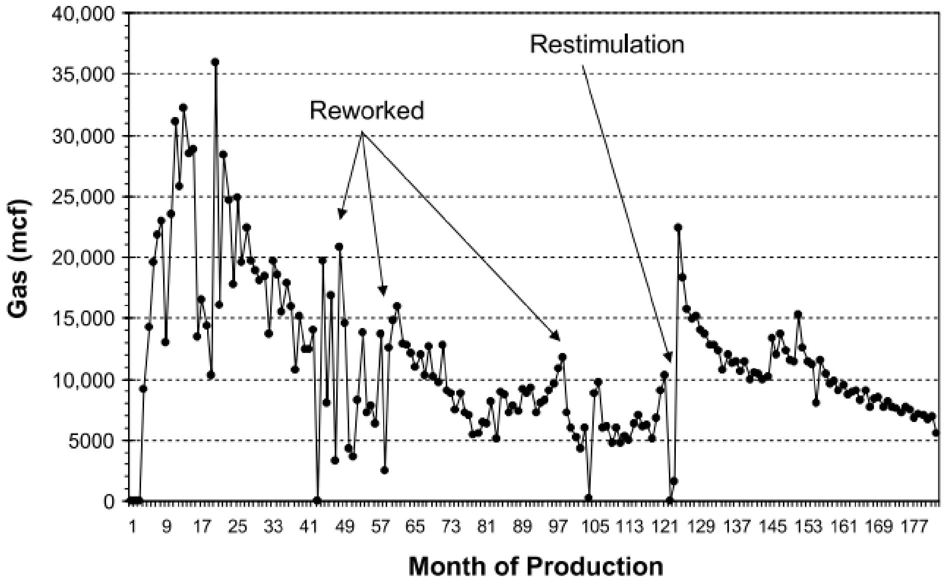

Figure 6.7 *'Production decline curve the the MEC 2 T.P. Sims vertical well that has produced 2.025 bcf of gas. The well was restimulated during the 122 months resulting in an increase in gas flow'* (Jarvie et al, 2007).

7 Conclusions

7.1 Stimulation techniques

The most well-known and widely applied stimulation techniques are acidizing and hydraulic fracturing.

In summary, when relatively limited performance enhancement is necessary (<50%), it can be sufficient to perform matrix acidizing. A bilateral design with acid treatment may result in up to 90% enhancement. Slant or horizontal drilling may, under circumstances, add to the increase of the PI.

Soft hydraulic fracturing can be considered for higher performance gains. This technique is well adapted for low differential stress environments (so the stresses from different directions do not differ too much), because tensile fracturing is the dominant mode of failure in response to high-pressure fluid injection.

In the case of high differential stress environments, soft hydraulic stimulation can be adapted by using multi-stage, with short packed intervals, which avoids the reactivation of any pre-existing – critically – stressed fractures.

Complementary to both methods, possible thermal effects of cold water injection (fracture development due to contraction of cooled rock) may need to be taken into consideration. Geomechanical simulation can assist in evaluating thermal effects in conjunction with the aforementioned methods.

Fines migration and / or reservoir integrity may become a problem when the flow rate is increased, especially when the reservoir rock is less consolidated.

7.2 Triassic

Acidization

- If the reservoir permeability turns out to be extremely low (< 1 mD), acid treatment may not be the preferred choice.
- The diagenetic history for relatively shallow occurrences of the Triassic (up to ~3000m) will likely differ from the relatively deep occurrences (>4000m). The type of cement may then also be different. This requires a different acid job design.
- Several authors with field experience conclude that the failure of acid jobs is often due to incorrect design. One should pay heed to this important message.
- While bullheading may enhance penetration of acid into the reservoir, this may induce acid fractures. The damage zone will not be dissolved. The fractures may close again after the pressure is relieved, thereby limiting the efficiency of the acid job.
- Acid stimulation in case of very low reservoir permeability will increase the geothermal power, but the latter will remain low.
- For tight reservoirs for the best results, the advised acid volume is low.
- The negative skin as a result of acid stimulation is unlikely to be much larger than about -2.

Hydraulic Stimulation

- Given the approximate NW-SE direction of the main horizontal stress σ_1, hydraulic fractures will develop in the direction of the line connecting both wells. This may accelerate the cold front breakthrough.
- Typically fractures have a skin of around -4 to -5 in practice.
- If the initial reservoir permeability is very low, the resulting geothermal potential, after hydraulic stimulation, will still be modest.
- An estimate of the success rate of a stimulation should be part of the job design.

Horizontal well

- Relatively short unstimulated horizontal wells are less efficient than a vertical well for the given reservoir thickness and likely anisotropies.
- Long unstimulated horizontal wells should preferably be drilled parallel, or away from each other, to prevent premature breakthrough.
- In case the horizontal well is hydraulically stimulated, the orientation of both laterals and fractures should be chosen carefully in order to prevent premature breakthrough.

7.3 Rotliegend

The problems encountered in the MDM-GT-03 well are complex. It is difficult to identify one single culprit, which makes it difficult to pinpoint a clear remedy.

Based on the indirect sediment analysis it can be concluded that clay swelling is unlikely to occur due to the low amounts of relevant clay minerals recognized in the reservoir rocks. However, based on the sediment composition no general statement can be given for the potential formation of carbonate and/or sulphate minerals near the well. Formation water analysis may provide additional information of the precipitation potential of certain minerals.

From the analysis of the formation water it can be concluded that carbonates and sulphates are under-saturated. Hence precipitation of minerals from the formation water near the injection well is unlikely. This also means that scaling as possible source of the observed well damage / positive skin is unlikely. Small amounts of barite may be formed and should be considered as scaling product in the well. Barite scale is currently not observed in the filters of the Middenmeer installation after the heat exchanger.

The observed limited flow and the development of a negative skin at the MDM-GT-03 suggest local clogging *near* the well, rather than *in* the well. This needs to be confirmed by a thorough geological analysis of the local reservoir and the well itself, in order to confirm the reported positive skin, assisted by evidence from relevant nearby wells. The abundant occurrence of anhydrite and clay in the cuttings, in combination with the increased gamma, may also point to a poor reservoir quality.

In case matrix acidizing is applied as a stimulation technique, it is recommended to:

- Design the acid treatment based on: the type of formation damage, and knowledge on the local mineralogy, multiple fluids and pumping stages, the drilling mud composition, and reactions between fluids and formation minerals considering the fast reaction kinetics at high temperatures at high depth.
- Monitor prior to, during and after the acid treatment operation in order to predict the evolving damage skin factor successfully.

8 Recommendations

Based on the study presented above, enriched with the findings and conclusions from two specific Dutch test-cases, the following recommendations for the geothermal sector in The Netherlands are given:

The challenge for the Dutch geothermal sector focussing on the direct use of heat is twofold:

- increase the flow (and thereby power) of conventional geothermal installations (to a depth of 3 kilometers);
- increase the power by tapping into higher temperatures from greater depths (to a depth of 4 kilometers).

This study was designed to produce a vision on technical developments towards higher flows from a depth-interval from 2 to 4 kilometers within the next 4 to 5 years.

Although there is a long history of well stimulation within the oil & gas sector, there is still a lot of activity to a) translate these technologies to the geothermal sector *with its specific requirements* and b) develop new technologies.

For the next 4 to 5 years the emphasis is on known technologies, which are, or will become available for the geothermal sector. The short list narrowed down to 3 technologies: *acidization, hydraulic mode-1 (or tensile) stimulation* and *radial jetting*

For the geothermal sector the above mentioned soft stimulation technologies lead to the following recommendations:

- In case the flow should be increased on a short term by less than 50% without making a huge investment; acidization should be considered, without economizing on upfront investigation and design.
- In case the flow should be increased by more than 50% either Hydraulic mode-1 stimulation or radial jetting can be considered. In both cases the application currently implies taking a leap as early adopter or await the demonstration outcomes from SURE (European project on radials, including demonstration) and DESTRESS (European project on soft stimulation technologies: demonstration of hydraulic mode-1 stimulation and acidization)

In all cases it has become apparent that in-depth knowledge of the reservoir (composition, fluids, geology, ..) is indispensable. Local variations in geology can play a crucial role.

Considering the early stages of innovation and implementation of soft stimulation technologies for geothermal systems, it is of huge importance to share the knowledge and experiences gained within the Dutch geothermal sector. It may be tempting to consider the above mentioned technologies readily available, but one should remember that (almost) none have been demonstrated in a geothermal system, or showed durability on the longer term (performance, state of the materials used, etc.). Make sure that the knowledge which will be developed in an European or National context, reaches the geothermal operators. For the next 4 to 5 years this will be the ‘kennisagenda’ which – amongst other topics – provides an in-depth inventory of stimulation technologies, or the Horizon2020 project SURE (on Radial Jetting) and DESTRESS (on Soft Stimulation in different geological settings), which both will start early next year.

Reminiscing that there are experiences in the oil- and gas sector; make sure the geothermal sector benefits from the existing knowledge, but be aware of and investigate the differences when applied to a geothermal reservoir.

It should be stressed that the further implementation of soft stimulation technologies is not a technical challenge only. Considering that even conventional geothermal systems can be considered to be innovative (see chapter 1.1), and that there is almost no experience with soft stimulation, implementation may require more than purely technical development and risk reduction. For the geothermal sector it is also important to educate, inform and support the innovators and early adopters for a broader implementation on the longer term.

Recommendations for acidization
In case matrix acidizing is applied as a stimulation technique, it is recommended to:

- Design the acid treatment based on: the type of formation damage, and knowledge on the local mineralogy, multiple fluids and pumping stages, the drilling mud composition, and reactions between fluids and formation minerals considering the fast reaction kinetics at high temperatures at depth.
- Monitor prior to, during and after the acid treatment operation in order to predict the evolving damage skin factor successfully.

Recommendations for hydraulic stimulation
- Although in lab environment, jetting of different lithogies is possible. However, this is not directly true for in-situ conditions. So site specific assessment of the applicability of radial jet drilling requires more detailed investigation of the site specific conditions and more sophisticated modelling to get a more accurate estimate of the expected revenues.
- Monitoring of the results of jetting directly after operations and on the longer term should provide insight in the effect(-ivness) and can provide a basis for the realization of durable results.

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Kennisagenda:
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Appendix A: Geology of the Rotliegend and Triassic geothermal reservoirs

Rotliegend

The Permian is divided into three lithostratigraphic groups: The Lower Rotliegend (volcanic and clastic rocks and limited geographic distribution), the Upper Rotliegend (fine to coarse grained clastic sediments and evaporites) and the Zechstein Group (mainly marine evaporites and carbonates) (Lokhorst, 1998).

Lower Rotliegend
The Lower Rotliegend Group is known as the Altmark Group in Germany and as the Karl Formation in Denmark, and the United Kingdom (Plein, 1995; Johnson et al., 1994). In the Netherlands, they are attributed to the Lower Rotliegend Group (Van AdrichemBoogaert and Kouwe 1997). Volcanic rocks of the Lower Rotliegend are widespread in Germany and Poland but only limited in the Netherlands (Ems Low, Dutch Central Graben and Horn Graben) (Lokhorst, 1998; Evans et al., 2003). The maximal thickness onshore the Netherlands yields maximal 80 m in the Ems Low (Plein, 1995). The volcanic rocks consist of rhyolite, andesite, and minor amounts of basalts and appear as lava flows and ignimbrites with partly intercalated tuffs and volcanoclastics (Marx et al., 1995; Plein, 1995; Benek et al., 1996).

Upper Rotliegend
Thick continental siliciclastics and evaporites were deposited in the Central European Basin under semi-arid to arid climate conditions (Glennie, 1972 and 1983). A general distribution of four facies types dominates the succession of sediments: (1) ephemeral fluvial systems (wadis) are located at the basin margin and consist mainly of sandstones, siltstones and conglomerates. The sediments form irregular interlocking with (2) aeolian depositions. (3) Playa lake and mudflats were deposited in the deepest parts of the basin and include (4) saline lake environments. In dry periods halite and other evaporites were deposited in the basin centre, whereas during more humid climate conditions the lake expanded and silt and clay were deposited in more marginal areas. The fine grained evaporitic Silverpit Formation in the northern half of the Netherlands and the sandy Slochteren Formation in the south may form the lateral equivalent of the German Elbe subgroup (Glennie 1998; Geluk, 2005). The Slochteren Formation comprises mainly sandstones and conglomerates of fluvial and aeolian origin whereas the Silverpit Formation is composed of claystone's, siltstones and evaporites (Geluk, 2005). Their transition occurs in a relatively narrow zone in the North of the Netherlands. Several claystone tongues of the Silverpit Formation reach far to the south into the sandy bodies of the Slochteren Formation.

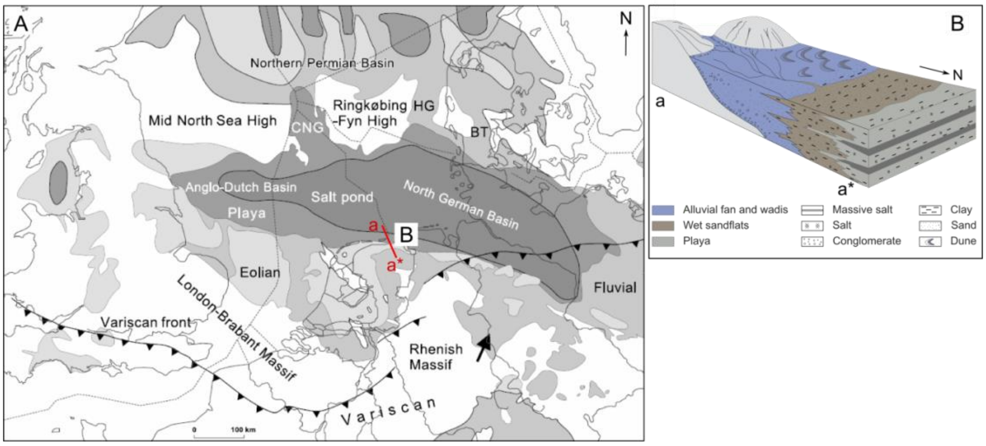

Figure 0.1 Distribution of Upper Rotliegend deposits in the Central European Basin System (**A**) and corresponding cross section (**B**); Adapted from Geluk (2005).

Triassic

The development of the Triassic in the Southern Permian Basin has been described among others by Ziegler (1990), Bachmann et al. in Doornenbal and Stephenson (2010), and for the Netherlands in detail by Van Adrichem-Boogaert and Kouwe (1994), Geluk (2005), Geluk et al. in Rondeel et al. (eds, 1993), and Geluk in Wong et al. (2007). This section aims at providing a brief overview of those Triassic formations that are relevant for geothermal exploration in the Netherlands.

After the Permian Zechstein, during which evaporites were formed, sedimentation continued in the Southern Permian Basin Area. The facies, however, became mainly continental (eolian, fluvial, lacustrine, paralic, but also some shallow marine). Deposition of the Triassic Buntsandstein was governed by the development of a large fluvial system which transported clastics from the Massif Central and Vosges areas in France northward through the Ruhr Valley Graben, into the West Netherlands Basin and the Off Holland Low. Additionally, the London Brabant Massif served as local source of clastic input. During the earliest Triassic (Induan), the coarse clastics were still trapped in the Ruhr Valley Graben. Later uplift of the hinterland transported the clastic deposits further north into the basin. Influx of course clastics (Lower Germanic Trias) ceased during the Middle Triassic (Upper Germanic Trias). The development (thickness and facies) of the rocks comprising the Buntsandstein has strongly been governed by the Hardegsen extensional phase.

The boundary with the underlying Zechstein deposits is conformable. The thickness of the deposits in the Central Graben is up to 2500 meters, in the Ems Low 2000 meters, while in other basins such as the West Netherlands Basin it is up to 1000 meters. Outside the basins the Triassic deposits are either thin or absent, like over the Netherlands Swell which developed over the pre-Triassic Texel-IJsselmeer High, where carbonate oolite beds were formed (Figure 0.3).

After the multiple rifting phases that accommodated the sediments comprising the Triassic Formations, several inversion phases took place in the West Netherlands Basin, during which previous normal faults were re-activated in a transpressional manner (De Jager et al., 1996, Worum and Michon 2005). This resulted in deformation, uplift and erosion. Hence, some formerly deeply buried blocks are now present at relatively shallow depth. The deep burial however has had its imprint on the development of the porosity and permeability.

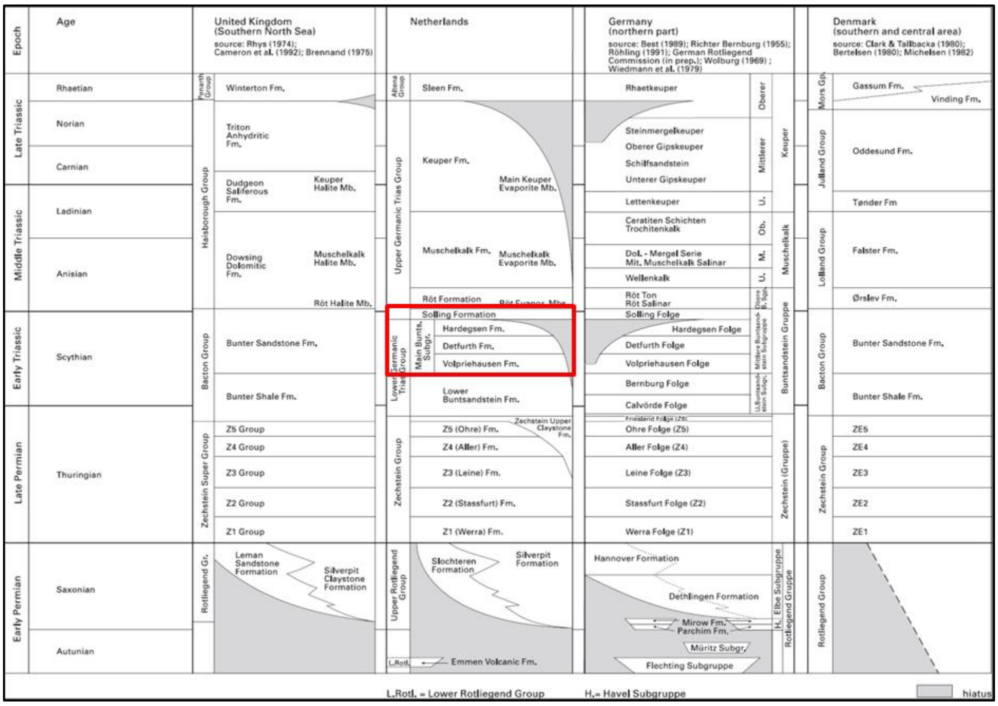

Figure 0.2 Regional lithostratigraphic correlation chart of the Triassic for the Netherlands and neighbouring countries (van Adrichem Boogaert and Kouwe 1994 figure D.5), showing the Volpriehausen, Detfurth, Hardegsen and Solling Formations.

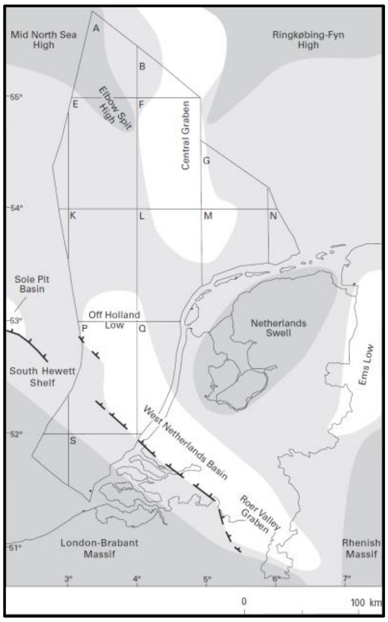

Figure 0.3 Triassic to Liassic structural elements (van Adrichem Boogaert and Kouwe 1997). Onshore, most sedimentation took place in the West Netherlands Basin and the Ems Low. Over the Netherlands Swell, sedimentation was absent or limited.

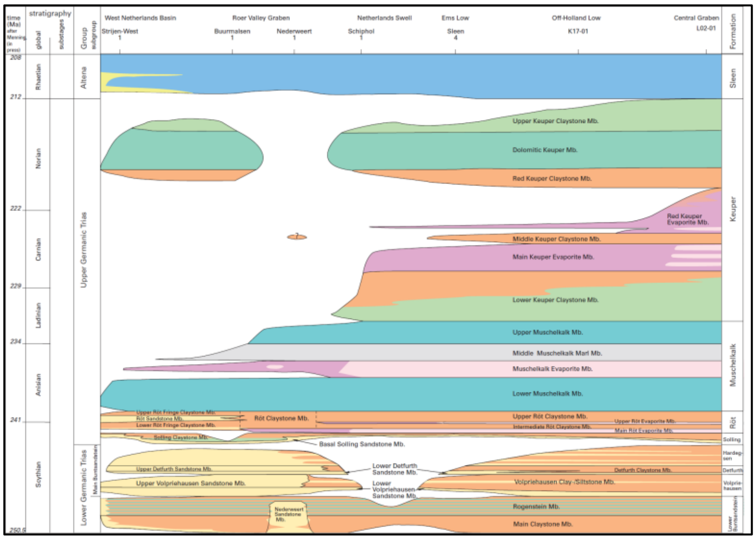

Figure 0.4 Triassic litho-chronostratigraphic chart. (van Adrichem Boogaert and Kouwe 1997 figure E.4)

Lower Germanic Trias Group
The Lower Germanic Trias comprises the Lower and Main Buntsandstein groups.

Lower Buntsandstein Formation
The Lower Buntsandstein Formation mainly comprises the Main Claystone and Rogenstein Members. They are composed of fine-grained lacustrine sandstones, claystones and siltstones. Their development and thickness is very uniform. Internal fining-upward sequences can be correlated over very large distances. They are not targeted for geothermal exploration because of the fine-grained nature of the sediments. Only in the south-eastern part of the Netherlands, however, up to 200 meter thick sandstones are present that belong to the Nederweert Sandstone Member. Its lateral extent within the Netherlands is very limited. Until now, the Nederweert Sandstone Member has not been a target for geothermal exploration.

Main Buntsandstein Subgroup
The Main Buntsandstein Subgroup consists of a cyclic alternation of (sub-) arkosic[21] sandstones and clayey siltstones. Each of the composing Formations (Volpriehausen, Detfurth and Hardegsen) consists of a large scale fining upward sequence, with silt- and claystones on top. Superimposed on this first order cycle are smaller scale cycles. The Formations are considered to be tectono-stratigraphic units, their development driven by pulses of extension tectonics of the Hardegsen phase. In the southern part of the Netherlands, the formations are dominantly sandy.

Volpriehausen Formation
The Lower Volpriehausen Sandstone Member consists of sandstones with a quartz percentage slightly below 50%. It is cemented by a high percentage of calcite and dolomite cement in the lowermost part. In the southern part, the facies is dominantly

[21] Arkosic: rich in feldspar

fluvial, to the north more aeolian (Figure 0.7). The average porosity in the West Netherlands Basin is up to 10%. Salt plugging is common in the Central Graben.

The Upper Volpriehausen Sandstone Member consists of reddish brown silty sandstone with dolomite, anhydrite and ankerite[22] cement. Its thickness has been significantly reduced by erosion (Detfurth and Solling unconformities).

Toward the Netherlands Swell the Upper Volpriehausen Sandstone grades into the Volpriehausen Clay-Siltstone Member (shale-out). It consists of lacustrine siltstones and marls, and subordinate sandstone. The sandstone is fine grained and cemented by dolomite, calcite and ankerite. It exhibits considerable variation in thickness.

The Lower Volpriehausen Sandstone Member has the best reservoir characteristics, but the Upper Volpriehausen sandstone is considered a waste zone owing to cementation.

Detfurth Formation
The Detfurth Formation is considered the best reservoir interval. It shales out towards the north. It occurs in Early Triassic lows. The thickness in the West Netherlands Basin, where it consists entirely of sandstone, is 20-40 meter. It shows a low gamma, with quartz up to 60%, loosely quartz cemented. The porosity in the West Netherlands Basin is 15-20%.

The Detfurth Claystone Member follows the thickness trend of the Lower Detfurth Sandstone Member. It consists of claystones with thin intercalations of siltstone, gradually grading into sandstone in the southern offshore and onshore.

The Upper Detfurth Sandstone Member contains two claystone intervals. In the Central Graben the porosity has often been destroyed by to salt plugging.

Hardegsen Formation
The Hardegsen Formation consists of an alternation of siltstones and sandstones, in the West Netherlands Basin margin area limited to massive sandstones. Only erosional remains. The occurrence of altered feldspars indicates leaching took place. Porosities are up to 20%. Due to pre-Solling erosion, its occurrence is limited to lows – only erosional remains. The thickness in the West Netherlands Basin is up to 70 meter.

Upper Germanic Trias Group
The upper Germanic Trias comprises the Solling, Röt, Muschelkalk and Keuper Formations. With the exception of the Solling Formation, which contains a lower Basal Solling Sandstone Member, the sediments of the Upper Germanic Trias comprise mainly fine-grained deposits, siltstones and claystones (Solling), evaporites, claystones and siltstones (Röt), limestones, dolomites and marls and evaporites (Muschelkalk) and anhydrites, halite and claystones (Keuper). This makes them an unattractive prospect for geothermal purposes.

[22] Ankerite is a calcium, iron, magnesium, manganese carbonate mineral $Ca(Fe,Mg,Mn)(CO_3)_2$

Mineralogical composition relevant for choice of stimulation techniques
Similarly to the Rotliegend, different facies exist in the Volpriehausen, Detfurth, Hardegsen en Solling Formations, mainly fluvial and eolian. This influences the choice of stimulation technique. Early cement often includes calcite and dolomite. During burial, others cements may have formed, including quartz. The same statements as made for the Rotliegend in Table 0.1 are generally valid. Because of the complex burial and uplift history, it is extremely important to assess the rock chemistry and diagenetic history of the reservoir before deciding on a stimulation technique.

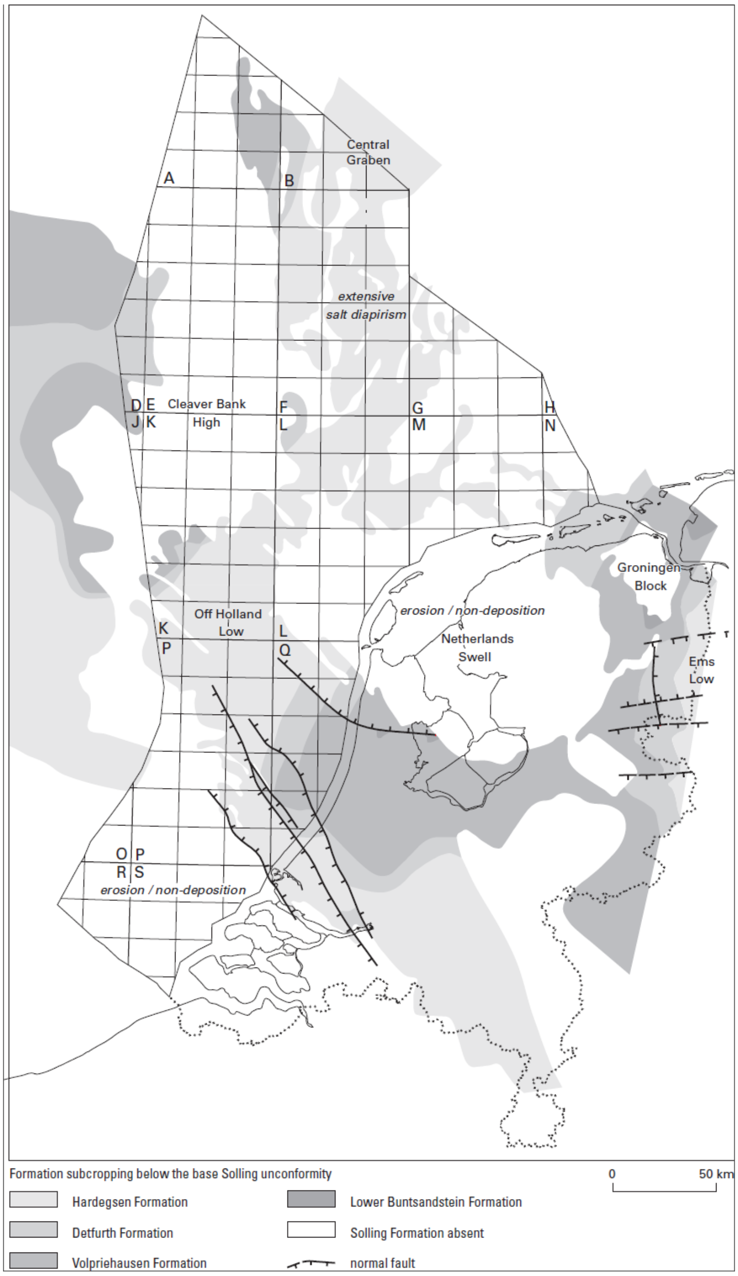

Figure 0.5 Formation subcrops below the Solling unconformity. In the more northern parts, the Volpriehausen Formation occurs, towards the south the Detfurth and Hardegsen (van Adrichem Boogaert and Kouwe 1997)

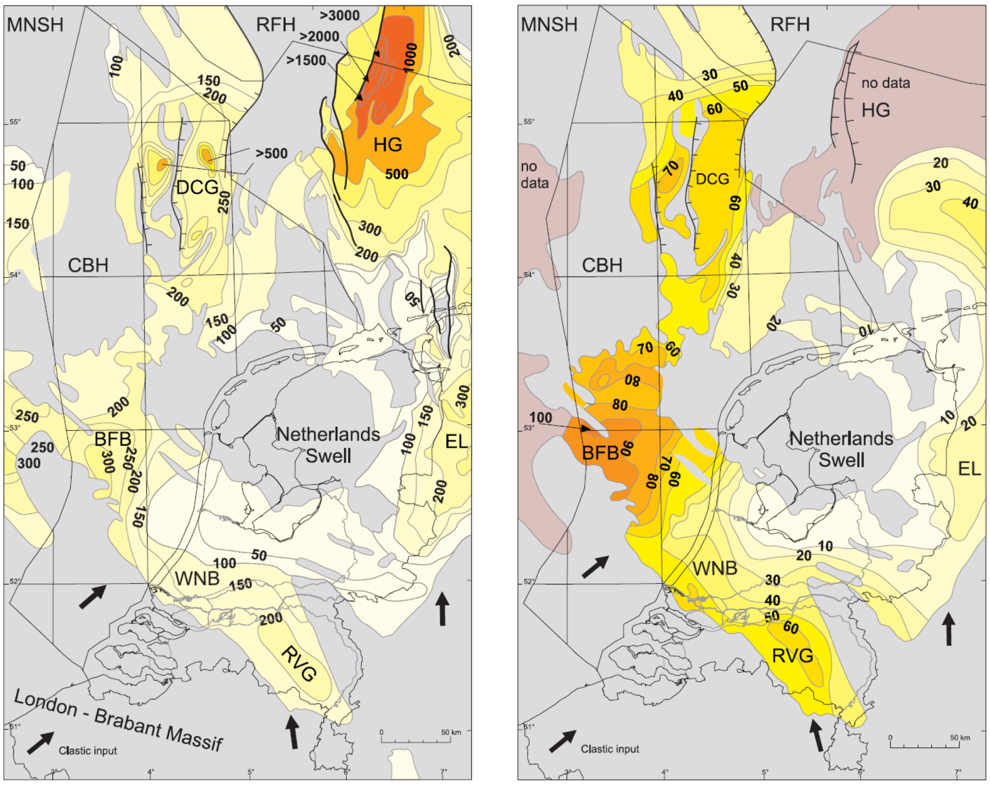

Figure 0.6 Isopach maps of the Main Buntsandstein (left) and Lower Volpriehausen (right). From Geluk, in Wong et al. (2007).

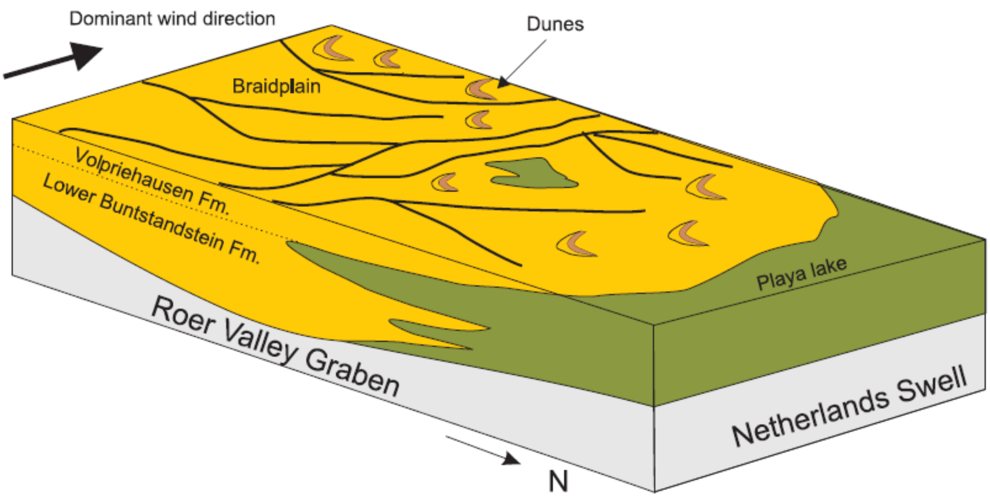

Figure 0.7 Depositional model for the Lower Buntsandstein and Volpriehausen Formations. Geluk, in Wong et al. (2007), showing the distribution of the sandy fluvial and aeolic facies versus the fine-grained playa lake deposits.

Appendix B: Chemical Reactions related to Matrix Acidization

The chemical reactions are:

Calcite

$2HCl + CaCO_3 \leftrightarrow CaCl_2 + CO_2 + H_2O$

Dolomite

$4HCl + CaMg\,(CO_3)_2 \leftrightarrow CaCl_2 + MgCl_2 + 2CO_2 + 2H_2O$

Siderite

$2HCl + FeCO_3 \leftrightarrow FeCl_2 + CO_2 + H_2O$

Quartz, clay, and feldspars are the main siliceous particles involved in damage of sandstones. The primary chemical reactions in sandstone acidizing are:

Sand=quartz

$4HF + SiO_2 \leftrightarrow SiF_4$ (silicon tetrafluoride tetrafluoride) $+2H_2O$

$SiF_4 + 2HF \leftrightarrow H_2SiF_6$ (fluosilicic acid)

Clays (kaolinite)

$Al_4Si_4O_{10}(OH)_8 + 24HF + 4H^+ \leftrightarrow 4AlF_2 + 4SiF_4 + 18H_2O$

(montmorillonite)

$Al_4Si_8O_{20}(OH)4 + 40HF + 4H^+ \leftrightarrow 4AlF_2 + 8SiF4 + 24H_2O$

Feldspars

(Mg, Na or K) $KAlSi_3O_8 + 14HF + 2H^+ \leftrightarrow K^+ + AlF_2 + 3SiF_4 + 8H_2O$

When Mud Acid Mixture (HCl:HF) is used, generally the acid concentrations vary from 6 to 12% for HCl and from 0.5 to 3% for HF (Morales Alcala, 2012). Portier et al. (2007) suggested concentrations of HCl up to 13.5% when the content of feldspar ranges from 15 to 30% (see Table 0.1).

Well and formation conditions	Treatment fluid recommendation
Bottomhole treating temperatures> 100°C	1.5% HF + 13.5% HCl
Permeability < 5md	1.5% HF + 13.5% HCl
Quartz content: Over 90% 50 to 90%	 3% HF + 12% HCl 3% HF + 12% HCl or retarded HF
Feldspar, 15 to 30%	1.5% HF + 13.5% HCl
Chlorite clay: 1 to 5% <5%	 3% HF + 10% Acetic 1.5% HF + 10% Acetic or Formic

Table 0.1 Alternate sandstone acid procedures for specific formation conditions (Portier et al., 2007, Report)